Capacity Market

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

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first six months of 2015, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 5-1 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the inclusion of imports which are not substitutes for internal capacity resources and inadequate performance incentives.

Overview

RPM Capacity Market

Market Design

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

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

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

unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[6] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[7]

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

Market Structure

- **PJM Installed Capacity.** During the first six months of 2015, PJM installed capacity decreased 6,985.5 MW or 3.8 percent, from 183,726 MW on January 1 to 176,740.5 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on June 30, 2015, 37.8 percent was coal; 33.6 percent was gas; 18.7 percent was nuclear; 3.9 percent was oil; 4.9 percent was hydroelectric; 0.5 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Market Concentration.** In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.[9]
- **Imports and Exports.** In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,149.5 MW for June 1, 2015, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2015/2016 Delivery Year (16,643.3 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,493.8 MW).

Market Conduct

- In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.

Market Performance

- In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.
- For the 2015/2016 Delivery Year, RPM annual charges to load were $9.6 billion.
- The Delivery Year weighted average capacity price was $126.40 per MW-day in 2014/2015 and $160.01 per MW-day in 2015/2016.

6 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.
9 151 FERC ¶ 61,067 (2015).

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first six months of 2015 was 7.7 percent, a decrease from 11.3 percent for the first six months of 2014.[10]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2015 was 82.5 percent, an increase from 80.2 percent for 2014.
- **Outages Deemed Outside Management Control (OMC).** In the first six months of 2015, 4.4 percent of forced outages were classified as OMC outages, and 0.1 percent of OMC outages were due to lack of fuel. OMC outages are excluded from the calculation of the forced outage rate used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Recommendations[11]

The MMU recognizes that PJM has proposed the Capacity Performance construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance construct addresses many of the MMU's recommendations. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[12]

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[13,14] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2013. Status: Adopted.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013. Status: Adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that clear, explicit operational protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends three changes with respect to capacity imports into PJM:

10 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data is for the six months ending June 30, as downloaded from the PJM GADS database on July 24, 2015. 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.

11 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

12 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).

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

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

— The MMU recommends that all capacity have firm transmission to the PJM border acquired prior to the offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted.)

— The MMU recommends that all capacity imports be required to be pseudo tied prior to the relevant Delivery Year in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. (Priority: High. First reported 2014. Status: Adopted.)

— The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted.)

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[15,16] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the rule requiring that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as planned for purposes of mitigation and exempted from offer capping be removed. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[17] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends two changes to the RPM solution methodology related to make-whole payments and the iterative reconfiguration of the VRR curve:

  — The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make-whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)

  — The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends improvements to the performance incentive requirements of RPM:

  — The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2013. Status: Adopted.)

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

  — The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market. (Priority: Medium. First reported 2013. Status: Adopted.)

  — The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[18] (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)

15 See PJM Interconnection, L.L.C., Docket No. ER12-513 (December 1, 2011) ("Triennial Review").

16 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

17 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

18 For more on this issue and related incentive issues, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_

Conclusion

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in the first six months of 2015. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first six months of 2015.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[19,20,21,22,23] In 2014 and 2015, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

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

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

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

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

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

Table 5-2 RPM related MMU reports, 2014 through 2015

Date	Name
January 8, 2014	IMM Comments re Capacity Technical Conference No. AD13-7-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_AD13-7-000_20140109.pdf
January 8, 2014	IMM Answer re Limited DR Cap No. ER14-504-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-504-000_20140108.pdf
January 8, 2014	IMM Answer re RPM Import Cap No. ER14-503-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-503-000_20140108.pdf
January 27, 2014	IMM Complaint and Motion to Consolidate re DR Resources Docket No EL14-xxx-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Complaint_and_Motion_to_Consolidate_EL14-xxx_20140127.pdf
January 29, 2014	IMM Motion for Clarification and/or Reconsideration, or, in the Alternative, Rehearing re Make-Whole Waiver Docket No. ER14-1144-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Motion_for_Clarification_or_Reconsideration_or_Rehearing_ER14-1144-000_20140129.pdf
January 29, 2014	IMM Comments re Offer Cap Waiver Docket No. ER14-1145-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_ER14-1145-000_20140129.pdf
February 24, 2014	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20140224.pdf
March 7, 2014	IMM Comments re January 28 Deficiency Letter Docket No. ER14-503-001 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_ER14-503-001_20140307.pdf
March 11, 2014	IMM Comments re Response to Deficiency Notice Docket Nos. ER14-822-001 and EL14-20-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_and_Motion_for_leave_to_Answer_EL14-20-000_20140311.pdf
March 24, 2014	IMM Comments re Response to Deficiency Notice Docket Nos. ER14-822-001 and EL14-20-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_Docket_Nos._ER14-822-001_EL14-20-000_20140324.pdf
March 26, 2014	IMM Comments re Invenergy Waiver Docket No. ER14-1475-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Brief_EL08-14-010_20140407.pdf
March 26, 2014	Informational Filing re Waiver to Permit Make-Whole Payments Docket No. ER14-1144-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Make_Whole_Waiver_Report_ER14-1144_000_20140326.pdf
April 18, 2014	Analysis of the 2016/2017 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_20162017_RPM_Base_Residual_Auction_20140418.pdf
April 30, 2014	IMM Answer to PJM re RPM Reform Docket No. ER14-1461-000,-001 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-1461-000-001_20140430.pdf
May 9, 2014	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2015/2016, 2016/2017 and 2017/2018 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20140509.pdf
June 27, 2014	IMM Protest re CPV Maryland CfD Docket No. ER14-2106-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Protest_Docket_No_ER14-2106-000_20140627.pdf
June 27, 2014	IMM Protest re CPV New Jersey SOCA Docket No. ER14-2105-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Protest_Docket_No_ER14-2105-000_20140627.pdf
July 10, 2014	The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_20140710.pdf
August 26, 2014	The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf
August 29, 2014	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2015/2016, 2016/2017 and 2017/2018 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20140829.pdf
September 3, 2014	2017/2018 RPM BRA Sensitivity Analysis http://www.monitoringanalytics.com/reports/Presentations/2014/IMM_MIC_20172018_Sensitivity_Analyses_Revised_20140903.pdf
September 15, 2014	Capacity Performance Product Assumptions http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_ELC_Capacity_Performance_Product_Assumptions_20140915.pdf
September 17, 2014	IMM Comments on PJM's Capacity Performance Proposal and IMM Proposal http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_on_PJM's_Capacity_Performance_Proposal_and_IMM_Proposal_20140917.pdf
October 6, 2014	Analysis of the 2017/2018 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf
October 16, 2014	IMM Comments re PJM Triennial Review Docket No. ER14-2940-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_ER14-2940-000_20141016.pdf
October 22, 2014	IMM Comments re FE Complaint Docket No. EL14-55-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_Docket_No_EL14-55-000_20141022.pdf
October 28, 2014	IMM Proposal re PJM's Capacity Performance Proposal http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Proposal_re_PJM_Capacity_Performance_Proposal_20141028.pdf
November 19, 2014	IMM Motion to Intervene and Comments re 30 Day Notice Exception Docket No. ER15-135-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Motion_to_Intervene_and_Comments_Docket_No_ER15-135-000_20141119.pdf
December 3, 2014	IMM Reply Brief re Net Revenues Docket No. EL14-94-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Reply_Brief_Docket_No_EL14-94-000_20141203.pdf
December 12, 2014	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2015/2016, 2016/2017 and 2017/2018 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20141212.pdf
December 17, 2014	IMM Answer and Motion for Leave to Answer re Net Revenues Docket No. EL14-94-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_and_Motion_to_Answer_Docket_No_EL14-94-000_20141217.pdf
December 18, 2014	IMM Answer and Motion for Leave to Answer re DR Docket No. ER15-135-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_and_Motion_to_Answer_Docket_No_ER15-135-000_20141218.pdf
January 14, 2015	IMM Comments re Capacity Performance Docket Nos. EL15-738-000 and EL15-739-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_EL15-738-000_EL15-739-000_20150114.pdf
January 20, 2015	IMM Comments re Capacity Performance Docket No. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER15-623-000_EL15-29-000_20150120.pdf
January 29, 2015	IMM Protest re IMEA Waiver Docket No. ER15-834-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Protest_Docket_No_ER15-834-000_20150129.pdf
January 30, 2015	IMM Answer and Motion for Leave to Answer re Calpine Waiver Docket No. ER15-376-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Docket_No_ER15-376-000_20150130.pdf
February 13, 2015	Comments of the Independent Market Monitor for PJM re DR in RPM Docket No. ER15-852-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER15-852-000_20150213.pdf
February 22, 2015	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2015/2016, 2016/2017 and 2017/2018 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20150222.pdf
February 25, 2015	IMM Answer and Motion for Leave to Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000, Not Consolidated http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Docket_Nos_ER15-623-000_EL15-29-000_20150225.pdf
February 27, 2015	IMM Answer and Motion for Leave to Answer Errata re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000, Not Consolidated http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Errata_Docket_Nos_ER15-623-000_EL15-29-000_20150227.pdf
March 6, 2015	IMM Comments re Champion Energy Complaint Docket No. EL15-46-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_EL15-46-000_20150306.pdf
March 20, 2015	IMM Answer and Motion for Leave to Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_ER15-623-000_EL15-29-000_20150320.pdf
March 25, 2015	IMM Protest re IMEA Waiver Docket No. ER15-1232-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Protest_Docket_No_ER15-1232-000_20150325.pdf
March 26, 2015	IMM Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_to_Answer_Docket_Nos_ER15-623-000_EL15-29-000_20150326.pdf
April 15, 2015	IMM Comments re Capacity Performance Docket Nos. ER15-623-001 and ER15-1470-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_ER15-623-001_ER15-1470-000_20150415.pdf
June 30, 2015	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2016/2017, 2017/2018 and 2018/2019 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20150630.pdf
July 6, 2015	IMM Limited Request for Rehearing re Capacity Performance Docket Nos. ER15-623-000, -001 and El15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Limited_Request_for_Rehearing_Docket_Nos_ER15-623-000_001_and_20EL15-29-000_20150706.pdf
July 8, 2015	Intermittent Resources Capacity Performance Value Methodology http://www.monitoringanalytics.com/reports/Market_Messages/Messages/Intermittent_Resources_Capacity_Performance_Value_Methodology_20150708.pdf
July 20, 2015	IMM Comments re Capacity Performance Docket Nos. ER15-623-004 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_ER15-623-004_EL15-29-000_20150720.pdf

Installed Capacity

On January 1, 2015, PJM installed capacity was 183,726.0 MW (Table 5-3).[24] Over the next six months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 176,740.5 MW on June 30, 2015, a decrease of 6,985.5 MW or 3.8 percent from the January 1 level.[25,26] The 6,985.5 MW decrease was the result of deactivations (9,770.5 MW) and derates (212.0 MW) offset by capacity modifications (1,207.8 MW), new or reactivated generation (948.2 MW), an increase in imports (818.2 MW), and a decrease in exports (22.8 MW).

At the beginning of the new Delivery Year on June 1, 2014, PJM installed capacity was 176,737.4 MW, a decrease of 6,239.4 MW or 3.4 percent from the May 31 level.

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each Delivery Year, from June 1, 2007, to June 1, 2015, as well as the expected installed capacity for the next three Delivery Years, based on the results of all auctions held through the first six months of 2015.[27] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, and then decreased to 37.8 percent on June 1, 2015. Coal's share of installed capacity is projected to decrease further to 31.4 percent by June 1, 2017. The share of gas increased from 29.1 percent in 2007 to 33.6 percent in 2015, and is expected to increase to 42.2 percent in 2017. The percentage of hydroelectric installed capacity increased from 4.5 percent in 2007 to 4.9 percent in 2015, and is expected to decrease to 4.8 percent in 2017. The share of nuclear fell from 18.9 percent in 2007 to 18.7 percent in 2015, and is expected to continue to decrease to 16.5 percent in 2017. The share of oil decreased from 6.5 percent in 2007 to 3.9 percent in 2015, and is expected to increase to 4.1 percent in 2017, while solid waste remained at 0.4 percent and is expected to increase to 0.5 percent in 2017. Solar resources have increased their installed capacity share from 0.0 percent to 0.1 percent, and are expected to remain the same through 2017, and wind resources increased their installed capacity share from 0.0 percent to 0.5 percent, and are expected to remain unchanged through 2017.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2015

	1-Jan-15		31-May-15		1-Jun-15		30-Jun-15	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	72,741.3	39.6%	72,343.5	39.5%	66,878.1	37.8%	66,878.1	37.8%
Gas	59,662.6	32.5%	59,862.3	32.7%	59,460.1	33.6%	59,463.1	33.6%
Hydroelectric	8,765.3	4.8%	8,690.8	4.7%	8,698.8	4.9%	8,698.9	4.9%
Nuclear	32,947.1	17.9%	33,078.4	18.1%	33,071.5	18.7%	33,071.5	18.7%
Oil	7,907.6	4.3%	7,299.7	4.0%	6,853.4	3.9%	6,853.4	3.9%
Solar	97.5	0.1%	97.5	0.1%	128.0	0.1%	128.0	0.1%
Solid waste	781.9	0.4%	781.9	0.4%	771.3	0.4%	771.3	0.4%
Wind	822.7	0.4%	822.7	0.4%	876.2	0.5%	876.2	0.5%
Total	183,726.0	100.0%	182,976.8	100.0%	176,737.4	100.0%	176,740.5	100.0%

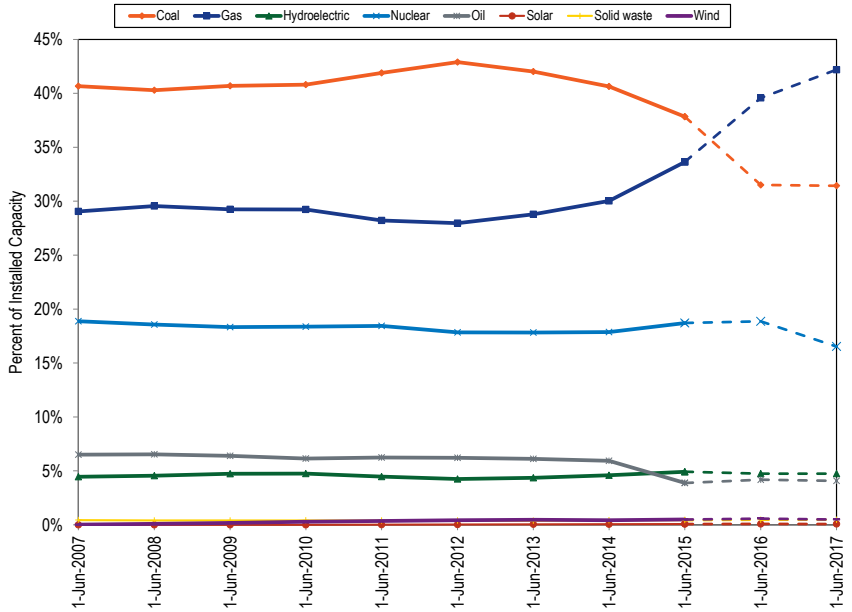
24 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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

26 Wind resources accounted for 822.7 MW of installed capacity in PJM on March 31, 2015. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data. There are additional wind resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market.

27 Due to EFORd values not being finalized for future Delivery Years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Figure 5-1 Percentage of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2017



RPM Capacity Market

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

Annual base auctions are held in May for Delivery Years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[28] In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.[29]

28 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
29 151 FERC ¶ 61,067 (2015).

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2014/2015 Delivery Year. The 13,078.0 MW increase was the result of new Generation Capacity Resources (9,787.1 MW), reactivated Generation Capacity Resources (430.0 MW), uprates (5,101.3 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (5,310.8 MW), a net decrease in capacity exports (2,547.0 MW), offset by deactivations (25,297.3 MW) and derates (2,909.9 MW).

Table 5-4 Generation capacity changes: 2007/2008 through 2015/2016

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,229.2	21.6	4,027.7	420.0	(1,556.6)
2014/2015	184,011.3	3,036.0	0.0	480.4	0.0	946.9	73.3	11,442.9	221.0	(7,273.9)
2015/2016	176,737.4									
Total		9,787.1	430.0	5,101.3	18,109.0	5,310.8	(2,547.0)	25,297.3	2,909.9	13,078.0

Demand

On June 1, 2015, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 65.1 percent (Table 5-5), down from 71.1 percent on June 1, 2014. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 34.9 percent, up from 28.9 percent on June 1, 2014. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make-whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year.

Table 5-5 Capacity Market load obligations served: June 1, 2015

	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	45,896.8	25,878.6	14,327.3	4,630.2	16,352.3	1,265.5	23,994.8	132,345.5
Percent of total obligation	34.7%	19.6%	10.8%	3.5%	12.4%	1.0%	18.1%	100.0%

Market Concentration

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a Delivery Year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[30] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[31] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[32] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base

30 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
31 PJM. OATT Attachment DD § 5.10 (a) (ii).
32 146 FERC ¶ 61,052 (2014).

Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled LDA.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given Delivery Year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[33]

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

Demand Resources

As shown in Table 5-6 and Table 5-8, capacity in the RPM load management programs was 12,149.5 MW for June 1, 2015 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2015/2016 Delivery Year (16,643.3 MW) less replacement capacity (4,493.8 MW). Table 5-7 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

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

Table 5-6 RPM load management statistics by LDA: June 1, 2014 to June 1, 2017[34,35,36]

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
DR cleared	14,943.0	7,452.4	2,976.9	2,268.4	220.9	999.5	468.4	920.0					
EE cleared	1,077.7	305.9	45.2	169.8	8.1	24.2	11.9	51.4					
DR net replacements	(6,731.8)	(3,778.7)	(1,651.1)	(1,010.7)	(156.0)	(550.4)	(231.1)	(428.9)					
EE net replacements	204.7	219.5	46.8	148.2	(6.8)	12.7	5.0	68.3					
RPM load management @ 01-Jun-14	9,493.6	4,199.1	1,417.8	1,575.7	66.2	486.0	254.2	610.8					
DR cleared	15,453.7	6,675.4	2,624.0	2,022.4	86.3	787.3	263.5	867.7	2,167.9				
EE cleared	1,189.6	279.0	73.1	164.8	3.1	26.4	11.5	59.3	142.0				
DR net replacements	(4,829.7)	(2,393.0)	(1,078.7)	(672.5)	(7.0)	(363.6)	(128.4)	(310.7)	(1,082.2)				
EE net replacements	335.9	230.4	48.5	149.2	0.0	12.4	2.7	61.1	15.2				
RPM load management @ 01-Jun-15	12,149.5	4,791.8	1,666.9	1,663.9	82.4	462.5	149.3	677.4	1,242.9				
DR cleared	12,710.5	5,354.2	2,006.5	1,603.6	105.7	630.8	226.7	664.1	1,825.1	470.8			
EE cleared	1,157.3	338.9	70.2	209.3	0.6	21.6	7.5	83.8	198.5	52.6			
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
RPM load management @ 01-Jun-16	13,867.8	5,693.1	2,076.7	1,812.9	106.3	652.4	234.2	747.9	2,023.6	523.4			
DR cleared	10,975.0	4,277.3	1,535.6	1,399.6	86.3	388.4	151.5	608.4	1,020.2	290.1	1,478.1	791.2	686.4
EE cleared	1,338.9	368.5	79.3	227.9	0.8	17.6	3.4	104.2	142.0	35.7	583.3	123.7	35.6
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-17	12,313.9	4,645.8	1,614.9	1,627.5	87.1	406.0	154.9	712.6	1,162.2	325.8	2,061.4	914.9	722.0

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

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

36 See PJM. OATT. Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 Delivery Year reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

Table 5-7 RPM load management cleared capacity and ILR: 2007/2008 through 2017/2018[37,38,39]

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,345.6	10,779.6	871.0	904.2	0.0	0.0
2014/2015	14,337.6	14,943.0	1,035.4	1,077.7	0.0	0.0
2015/2016	14,891.6	15,453.7	1,147.7	1,189.6	0.0	0.0
2016/2017	12,253.1	12,710.5	1,117.1	1,157.3	0.0	0.0
2017/2018	10,551.0	10,975.0	1,288.0	1,338.9	0.0	0.0

Table 5-8 RPM load management statistics: June 1, 2007 to June 1, 2017[40,41]

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	11,216.6	11,683.8	(3,184.8)	(3,318.8)	120.0	125.0	8,151.8	8,490.0
01-Jun-14	15,373.0	16,020.7	(6,458.4)	(6,731.8)	196.4	204.7	9,111.0	9,493.6
01-Jun-15	16,039.3	16,643.3	(4,653.7)	(4,829.7)	323.7	335.9	11,709.3	12,149.5
01-Jun-16	13,370.2	13,867.8	0.0	0.0	0.0	0.0	13,370.2	13,867.8
01-Jun-17	11,839.0	12,313.9	0.0	0.0	0.0	0.0	11,839.0	12,313.9

37 For Delivery Years through 2011/2012, certified ILR data is shown, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for Incremental Auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

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

39 See PJM. OATT. Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 Delivery Year reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

40 For Delivery Years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for Incremental Auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

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

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).[42]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity during that period. In the first six months of 2015, nuclear units had a capacity factor of 93.5 percent, compared to 92.1 percent in 2014; combined cycle units had a capacity factor of 58.3 percent in the first six months of 2015, compared to a capacity factor of 51.4 percent in the first three months of 2014; and steam units, which are primarily coal fired, had a capacity factor of 47.7 percent in the first six months of 2015, compared to 52.9 percent in the first three months of 2014.

42 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM GADS database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.

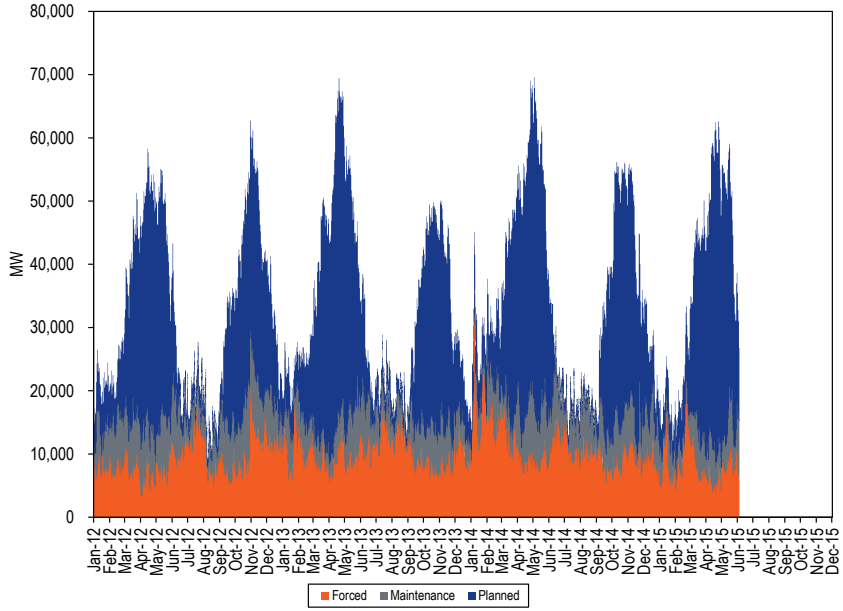
Table 5-9 PJM capacity factor (By unit type (GWh)): January through June of 2014 and 2015[43]

Unit Type	2014 (Jan-Jun) Generation (GWh)	2014 (Jan-Jun) Capacity Factor	2015 (Jan-Jun) Generation (GWh)	2015 (Jan-Jun) Capacity Factor	Change in 2015 from 2014
Battery	5.4	1.3%	1.5	0.3%	(0.9%)
Combined Cycle	57,523.0	51.4%	74,378.7	58.3%	6.9%
Combustion Turbine	5,054.4	3.8%	5,780.2	4.5%	0.7%
Diesel	314.8	17.6%	277.2	14.8%	(2.8%)
Diesel (Landfill gas)	724.2	45.1%	772.8	47.1%	1.9%
Fuel Cell	109.3	83.9%	113.6	87.2%	3.3%
Nuclear	134,954.5	92.1%	136,978.9	93.5%	1.4%
Pumped Storage Hydro	3,463.2	14.5%	2,709.2	11.4%	(3.2%)
Run of River Hydro	4,778.7	42.1%	3,875.4	32.7%	(9.4%)
Solar	197.7	16.6%	253.0	16.4%	(0.2%)
Steam	191,462.1	52.9%	162,230.8	47.7%	(5.2%)
Wind	8,678.0	31.5%	8,683.0	30.3%	(1.2%)
Total	407,265.3	49.6%	396,057.7	48.7%	(0.9%)

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The amount of MW on outages varies throughout the year. For example, the MW on planned outages are generally highest in the spring and fall, as shown in Figure 5-2, due to restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in "Performance By Month."

Figure 5-2 PJM outages (MW): 2012 through June 2015



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

The PJM aggregate EAF for the first six months of 2015 was 82.5 percent, an increase from 80.2 percent for the first six months of 2014. The PJM aggregate

43 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

EAF, EFOF, EPOF, and EMOF are shown in Figure 5-3. Metrics by unit type are shown in Table 5-10 through Table 5-13.

Figure 5-3 PJM equivalent outage and availability factors: 2007 to 2015

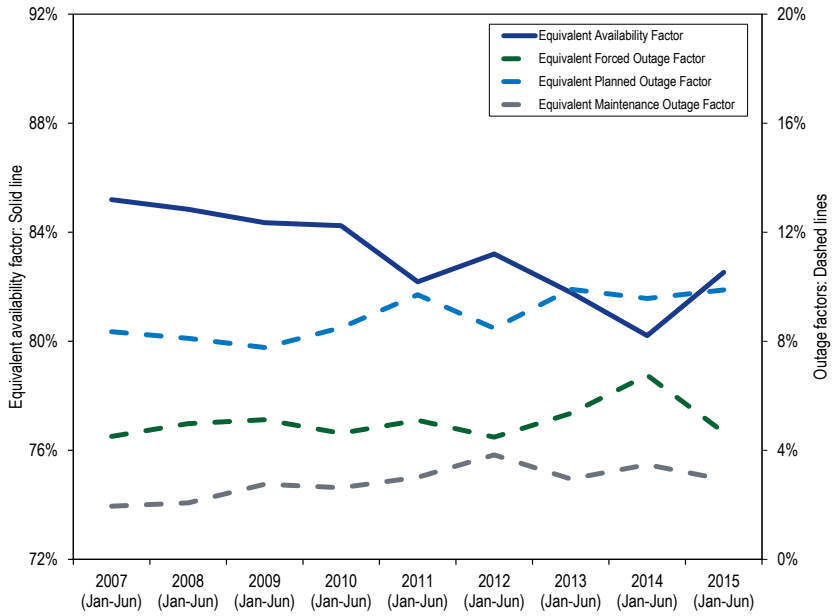


Table 5-10 EAF by unit type: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	88.9%	89.5%	86.5%	84.1%	83.5%	86.0%	82.4%	82.0%	84.3%
Combustion Turbine	89.1%	89.4%	92.5%	93.4%	93.0%	93.1%	89.6%	85.2%	89.4%
Diesel	87.8%	87.7%	91.4%	94.1%	94.9%	94.1%	93.7%	81.7%	86.9%
Hydroelectric	90.5%	89.4%	85.1%	86.1%	83.8%	88.9%	89.9%	83.3%	86.7%
Nuclear	93.9%	91.4%	89.6%	92.2%	88.6%	89.8%	90.8%	89.2%	90.9%
Steam	79.2%	79.5%	79.3%	78.3%	76.0%	76.4%	74.7%	74.0%	75.6%
Total	85.2%	84.8%	84.4%	84.2%	82.2%	83.2%	81.8%	80.2%	82.5%

Table 5-11 EMOF by unit type: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	1.9%	1.7%	3.3%	4.0%	2.9%	2.2%	3.2%	2.3%	2.1%
Combustion Turbine	2.6%	2.5%	2.4%	1.8%	1.8%	1.8%	1.7%	1.9%	2.4%
Diesel	2.3%	1.4%	1.5%	1.0%	2.7%	1.9%	1.6%	2.9%	2.8%
Hydroelectric	2.1%	2.4%	3.0%	2.2%	1.6%	1.6%	2.1%	3.6%	1.6%
Nuclear	0.3%	0.5%	0.7%	0.6%	2.0%	0.8%	0.6%	0.7%	1.1%
Steam	2.4%	2.6%	3.5%	3.4%	3.9%	6.2%	4.3%	5.5%	4.2%
Total	1.9%	2.1%	2.8%	2.6%	3.0%	3.8%	2.9%	3.5%	2.9%

Table 5-12 EPOF by unit type: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	7.5%	7.3%	7.3%	9.3%	11.2%	9.7%	11.4%	12.7%	11.3%
Combustion Turbine	3.1%	5.1%	3.6%	3.0%	3.8%	3.0%	3.7%	4.1%	5.0%
Diesel	0.8%	1.8%	0.4%	0.7%	0.0%	0.1%	0.4%	0.8%	0.6%
Hydroelectric	5.9%	6.8%	9.8%	11.0%	13.2%	5.7%	7.5%	11.2%	10.4%
Nuclear	4.7%	7.1%	5.7%	6.0%	7.7%	8.3%	7.2%	8.1%	6.8%
Steam	11.9%	9.8%	9.9%	10.8%	11.7%	10.2%	12.9%	11.1%	12.5%
Total	8.3%	8.1%	7.8%	8.5%	9.7%	8.5%	9.9%	9.6%	9.9%

Table 5-13 EFOF by unit type: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	1.7%	1.6%	2.9%	2.7%	2.4%	2.2%	3.0%	2.9%	2.2%
Combustion Turbine	5.3%	3.0%	1.6%	1.9%	1.3%	2.1%	5.0%	8.8%	3.2%
Diesel	9.1%	9.2%	6.8%	4.1%	2.4%	3.9%	4.3%	14.6%	9.6%
Hydroelectric	1.5%	1.5%	2.2%	0.7%	1.4%	3.9%	0.5%	1.9%	1.4%
Nuclear	1.1%	1.0%	4.0%	1.2%	1.8%	1.0%	1.4%	1.9%	1.1%
Steam	6.5%	8.2%	7.4%	7.5%	8.4%	7.2%	8.0%	9.4%	7.7%
Total	4.5%	5.0%	5.1%	4.6%	5.1%	4.5%	5.4%	6.8%	4.7%

Generator Forced Outage Rates

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

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[44] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for the first six months of 2015 was 7.7 percent, a decrease from the 11.3 percent average PJM EFORd for the same period 2014. Figure 5-4 shows the average EFORd since 2007 for all units in PJM.

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

Figure 5-4 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2015

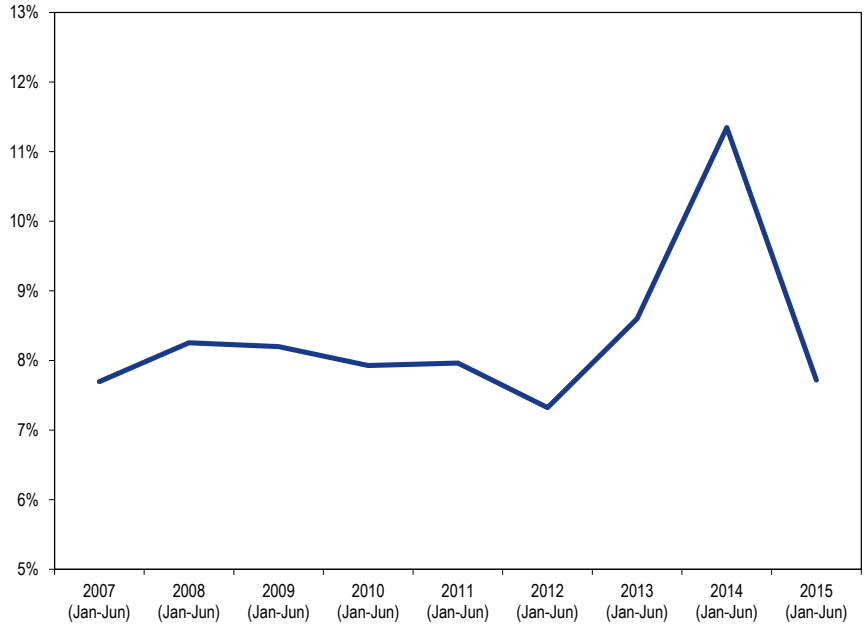


Table 5-14 shows the class average EFORd by unit type. Combustion turbine units had the highest class average rate of EFORd.

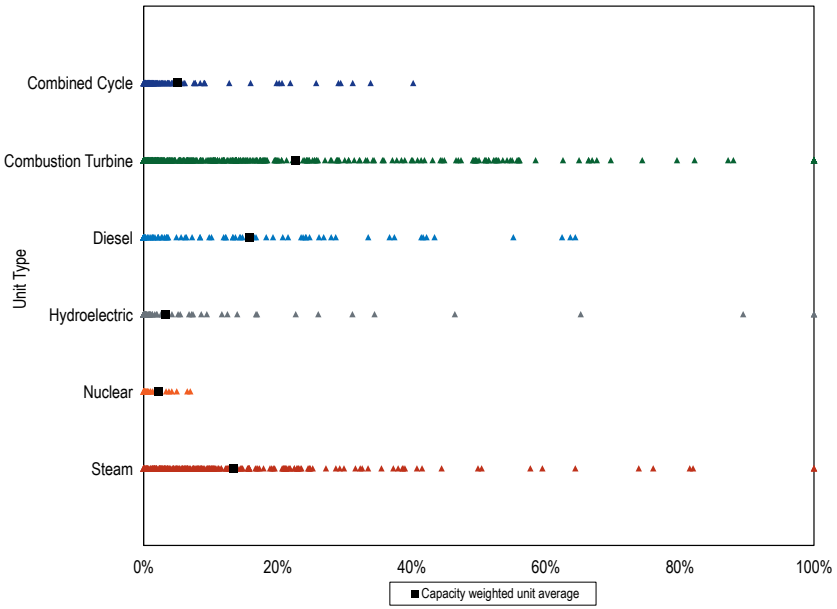
Table 5-14 PJM EFORd data for different unit types: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	3.9%	3.4%	5.0%	4.3%	3.5%	2.8%	3.8%	5.1%	3.0%
Combustion Turbine	16.7%	14.2%	10.3%	13.8%	8.4%	8.8%	14.1%	22.7%	12.8%
Diesel	10.6%	10.0%	8.5%	5.8%	6.4%	5.1%	4.4%	15.8%	10.9%
Hydroelectric	2.1%	2.2%	2.5%	1.1%	2.0%	5.5%	0.8%	3.3%	1.6%
Nuclear	1.2%	1.1%	4.0%	1.5%	2.1%	1.2%	1.6%	2.3%	1.2%
Steam	8.7%	10.7%	10.2%	9.8%	11.5%	10.4%	11.4%	13.4%	10.6%
Total	7.7%	8.3%	8.2%	7.9%	8.0%	7.3%	8.6%	11.3%	7.7%

Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates within each unit type. The distribution of EFORd by unit type is shown in Figure 5-5. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Combustion turbine units had the greatest variance in EFORd, while nuclear units had the lowest variance in EFORd values in 2015.

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



Other Forced Outage Rate Metrics

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

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

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

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

Outages Deemed Outside Management Control

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

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

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations of XEFORd, which are used to determine the level of unforced capacity for specific units in PJM's Capacity Market. Thus, the PJM capacity market rules, as currently written, create an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define

capacity available for sale, the PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC.

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[45] For NERC, an outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[46] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per NERC.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metrics used in the Capacity Market.[47] That choice was made by PJM and can be modified without violating any NERC requirements.[48] It is possible to have an OMC outage under the NERC definition, which PJM does not define as an OMC outage for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

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

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 5-15 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 4.4 percent of all forced outages in the first six months of 2015. The largest contributor to OMC outages, other switchyard equipment outages, was the cause of 32.2 percent of OMC outages and 1.4 percent of all forced outages. The level of OMC outages, 4.4 percent of all forced outages, is down significantly from 2013, when OMC outages were 16.8 percent of all forced outages.

45 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>.

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

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

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

Table 5-15 OMC Outages

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Other switchyard equipment	32.2%	1.4%
Switchyard circuit breakers	24.6%	1.1%
Transmission line	17.5%	0.8%
Transmission equipment beyond the 1st substation	5.1%	0.2%
Switchyard transformers and associated cooling systems	4.6%	0.2%
Transmission system problems other than catastrophes	3.7%	0.2%
Other fuel quality problems	2.0%	0.1%
Flood	1.9%	0.1%
Lack of fuel	1.7%	0.1%
Transmission equipment at the 1st substation	1.6%	0.1%
Other miscellaneous external problems	1.2%	0.1%
Lightning	1.2%	0.1%
Lack of water	1.0%	0.0%
Storms	0.9%	0.0%
Switchyard system protection devices	0.5%	0.0%
Tornado	0.3%	0.0%
Wet coal	0.1%	0.0%
Other catastrophe	0.1%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Total	100.0%	4.4%

An outage is an outage, regardless of the cause. It is inappropriate that units on outage do not have to reflect that outage in their outage statistics, which affect their performance incentives and the level of unforced capacity and therefore capacity sold. No outages should be treated as OMC because when a unit is not available it is not available, regardless of the reason, and the data and payments to units should reflect that fact.[49]

The level of OMC lack of fuel outages, 1.7 percent of OMC outages and 0.1 percent of all forced outages, is lower than recent years. In 2011 and 2012, OMC lack of fuel outages were 5.5 percent of all forced outages in 2011 and 4.6 percent of all forced outages in 2012.

Lack of fuel is an example of why, even if the OMC concept were accepted, many types of OMC outages are not actually outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. These are economic issues within the control of management and the resultant tradeoffs should be reflected in actual forced outage rates rather than ignored by designation as OMC. It is significant that some OMC outages are classified as economic. Firm gas contracts, including contracts with intermediaries, could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage.

If a particular unit or set of units have outages for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.

The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market after appropriate notice. OMC outages should not be reflected in forced outage metrics which affect market payments to generating units.

Performance Incentives

There are a number of performance incentives in the current capacity market design, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market.[50] These incentives will change when the Capacity Performance market design is implemented but remain essential

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

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

reasons why the incentive components of Capacity Performance design were necessary. The most basic incentive is that associated with the reduction of payments for a failure to perform. In any market, sellers are not paid when they do not provide a product. That is only partly true in the PJM Capacity Market. In addition to the exclusion of OMC outages, which reduces forced outage rates resulting in payments to capacity resources not consistent with actual forced outage rates, other performance incentives are not designed to ensure that capacity resources are paid when they perform and not paid when they do not perform.

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

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

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

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

Peak Period Capacity Shortfall = TCAP – PCAP

The Peak-Hour Period Availability Charge is equal to the seller's weighted average resource clearing price for the delivery year for the LDA.[51]

The peak hour availability charge understates the appropriate revenues at risk for underperformance because it is based on EFORp and because it is compared to a five year XEFORd. Both outage measures exclude OMC outages. The use of a five year average XEFORd measure is questionable as the measure of expected performance during the delivery year because it covers a period which is so long that it is unlikely to be representative of the current outage performance of the unit. The UCAP sold during a delivery year is a function of ICAP and the final Effective EFORd,[52] which is defined to be the XEFORd calculated for the 12 months ending in September in the year prior to the Delivery Year.

This maximum level of RPM revenues at risk is reduced by several additional factors including the ability to net any shortfalls against over performance across all units owned by the same participant within an LDA and the ability to use performance by resources that were offered into RPM but did not clear as an offset.[53]

Excess Available Capacity (EAC) may also be used to offset Peak Hour Availability shortfalls. EAC is capacity which was offered into RPM Auctions, did not clear but was offered into all PJM markets consistent with the obligations of a capacity resource. EAC must be part of a participant's total portfolio, but does not have to be in the same LDA as the shortfall being offset, unlike the netting provision.[54]

There is a separate exception to the performance related incentives related to lack of gas during the winter period. Single-fuel, natural gas-fired units do not face the Peak-Hour Period Availability Charge during the winter if the capacity shortfall was due to nonavailability of gas to supply the unit.[55] The result is an exception, analogous to the lack of fuel exception, except much broader, which appears to have no logical basis.

There is a separate exception to the performance related incentives related to a unit that runs less than 50 hours during the RPM peak period. If a unit runs for less than 50 peak period service hours, then the EFORp used in the calculation of the peak hour availability charges is based on PCAP calculated using the lower of the delivery year XEFORd or the EFORp.[56]

51 PJM. OATT Attachment DD § 10 (j).

52 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), p. 159
53 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.
54 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.1.
55 PJM. OATT Attachment DD § 7.10 (e).
56 PJM. OATT Attachment DD § 7.10 (e).

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[57]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[58]

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

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

Not all unit types are subject to RPM performance incentives. In addition to the exceptions which apply to conventional generation as a result of EFORp and XEFORd calculations, wind, solar and hydro generation capacity resources are exempt from key performance incentives. Wind and solar generation capacity resources are not subject to peak hour availability incentives, to summer or winter capability testing or to peak season maintenance compliance rules. Hydro generation capacity resources are not subject to peak season maintenance compliance rules.[59]

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

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

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

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

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

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[60] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.[61]

PJM EFOF was 4.7 percent in the first six months of 2015. This means there was 4.7 percent lost availability because of forced outages. Table 5-16 shows that forced outages for boiler tube leaks, at 24.5 percent of the systemwide EFOF, were the largest single contributor to EFOF.

57 PJM. OATT Attachment DD § 7.10 (e).
58 PJM. OATT Attachment DD § 7.10 (e).
59 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012) p. 98.

60 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.
61 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-16 Contribution to EFOF by unit type by cause: 2015

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	6.6%	0.0%	0.0%	0.0%	0.0%	31.7%	24.5%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	8.4%	6.4%
Economic	8.1%	26.9%	10.0%	2.9%	0.0%	3.6%	6.3%
Electrical	6.1%	18.2%	7.8%	0.6%	20.7%	2.6%	5.3%
Feedwater System	0.3%	0.0%	0.0%	0.0%	19.4%	5.3%	4.9%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	5.9%	4.5%
Fuel Quality	0.6%	0.2%	5.9%	0.0%	0.0%	5.5%	4.3%
Condensing System	0.7%	0.0%	0.0%	0.0%	2.1%	2.8%	2.3%
Miscellaneous (Boiler)	0.1%	0.0%	0.0%	0.0%	0.0%	2.7%	2.1%
Generator	13.6%	0.1%	5.8%	1.9%	0.0%	1.5%	2.1%
Boiler Piping System	6.2%	0.0%	0.0%	0.0%	0.0%	2.1%	2.0%
Valves	1.8%	0.0%	0.0%	0.0%	0.0%	2.3%	1.9%
Controls	1.3%	0.4%	0.0%	0.6%	5.8%	1.9%	1.8%
Inlet Air System and Compressors	15.0%	7.1%	0.0%	0.0%	0.0%	0.0%	1.7%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%	1.7%
Reserve Shutdown	0.2%	4.9%	4.1%	20.8%	0.0%	1.0%	1.7%
Auxiliary Systems	5.2%	6.3%	0.0%	0.5%	0.0%	0.8%	1.6%
Wet Scrubbers	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%	1.6%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	1.4%
All Other Causes	33.9%	36.0%	66.4%	72.7%	51.9%	15.7%	21.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-17 shows the categories which are included in the economic category.[62] Lack of fuel that is considered outside management control accounted for 1.2 percent of all economic reasons.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[63] 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.

62 The definitions of these outages are defined by NERC GADS.
63 The definitions of these outages are defined by NERC GADS.

Table 5-17 Contributions to Economic Outages: 2015

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	95.6%
Fuel conservation	1.3%
Lack of fuel (OMC)	1.2%
Lack of water (Hydro)	0.7%
Other economic problems	0.6%
Problems with primary fuel for units with secondary fuel operation	0.6%
Wet fuel (Biomass)	0.0%
Total	100.0%

EFORd, XEFORd and EFORp

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

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[64] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of combustion turbines and nuclear units, EFORp is lower than XEFORd, suggesting that units elect to take non-OMC forced outages during off-peak hours, as much as it is within their ability to do so. That is consistent with the incentives created by the PJM Capacity Market but it does not directly address the question of the incentive effect of omitting OMC outages from the EFORP metric.

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

Table 5-18 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for combustion turbine units.

Table 5-18 PJM EFORd, XEFORd and EFORp data by unit type[65]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.0%	3.0%	1.5%	0.0%	1.5%
Combustion Turbine	12.8%	11.7%	8.2%	1.1%	4.6%
Diesel	10.9%	10.0%	5.0%	0.9%	5.9%
Hydroelectric	1.6%	1.4%	1.8%	0.1%	(0.2%)
Nuclear	1.2%	1.1%	0.7%	0.1%	0.4%
Steam	10.6%	10.5%	7.1%	0.1%	3.5%
Total	7.7%	7.5%	5.0%	0.3%	2.7%

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