Q3

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent Market Monitor for PJM

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Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2013 Quarterly State of the Market Report for PJM: January through September.*

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M § II(f).

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Introduction

2013 Q3 in Review

The state of the PJM markets in the first nine months of 2013 was good. The results of the energy market and the results of the capacity market were competitive.

The goal of a competitive power market is to provide power at the lowest possible price, consistent with cost. PJM markets met that goal in the first nine months of 2013. The test of a competitive power market is how it reacts to change. PJM markets have passed that test so far, but that test continues. The significant changes in the economic environment of PJM markets continued in the first three quarters of 2013.

Continued success requires that market participants have access to all the information about the economic fundamentals of PJM markets necessary to make rational decisions. There are still areas where more transparency is required in order to permit markets to function effectively. The provision of clear, understandable information about market fundamentals matters. Information about the sources of operating reserve charges is notably opaque.

Continued success requires markets that are flexible and adaptive. However, wholesale power markets are defined by complex rules. Markets do not automatically provide competitive and efficient outcomes. There are still areas of market design that need further improvement in order to ensure that the PJM markets continue to adapt successfully to changing conditions. The details of market design matter.

The energy market dynamics changed in the first nine months of 2013. A combination of increased, weather related, demand, and higher fuel costs led to higher energy market prices than in the first three quarters of 2012. The load-weighted average LMP was $39.75 per MWh, 13.5 percent higher in the first nine months of 2013 than in the first nine months of 2012.

The price of natural gas was higher and the price of coal was relatively flat in the first nine months of 2013 compared to the first nine months of 2012. For example, the price of Northern Appalachian coal was 0.4 percent lower and the price of Central Appalachian coal was 2.8 percent higher, while the price of eastern natural gas was 54.0 percent higher. The price of natural gas, especially in the eastern part of PJM, increased in January but then decreased.

The results of the energy market dynamics in the first nine months of 2013 were generally positive for new coal units. As a result of the relative changes in fuel costs, coal-fired units were more competitive with gas-fired units. Coal-fired units' output increased by 6.2 percent in the first nine months of 2013 and gas-fired units' output decreased by 16.1 percent in the same period, reversing the trend towards reduced coal output.

The combination of higher energy prices and higher gas prices relative to coal prices resulted in significantly higher energy market net revenues for a new entrant coal plant in all PJM zones. In the first nine months of 2013, average energy market net revenues for a new entrant coal plant were 133 percent greater than in the first nine months of 2012 while average energy market net revenues for a new entrant gas fired combined cycle unit were 15 percent lower.

Markets need accurate and understandable information about fundamental market parameters in order to function effectively. For example, the markets need good information about constraints that can have substantial impacts on energy prices. For example, the markets need better information about unit outages in order to improve market transparency. For example, the markets need better information about transmission outages in order to improve market transparency. For example, the markets need better information about the reasons for operating reserve charges in order to permit market responses to persistent high payments of operating reserve credits. Data on the units receiving operating reserve credits and the reasons for those credits should be made publicly available to permit better understanding of operating reserve levels and to facilitate competition for providing the same services. Recent rule changes to improve the availability of information about unit retirements will make information available to potential entrants and increase the competitiveness of the capacity market.

The market design should permit market prices to reflect underlying supply and demand fundamentals. Significant factors that result in capacity market prices failing to reflect fundamentals should be addressed, including better LDA definitions, the effectiveness of the transmission interconnection queue process, the 2.5 percent reduction in demand that suppresses market prices, the continued inclusion of inferior demand side products that also suppress market prices and the role of imports.

The fact that up to congestion transactions are provided an artificial advantage over other virtual transactions must be addressed.

The PJM markets and PJM market participants from all sectors face significant challenges as a result of the changing economic environment. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets.

PJM Market Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM Market Summary Statistics, January through September 2012 and 2013[1]

	Jan - Sep 2012	Jan - Sep 2013
Load	591,517 GWh	592,209 GWh
Generation	602,561 GWh	600,784 GWh
Imports (+) / Exports (-)	801 GWh	3,474 GWh
Losses	12,778 GWh	13,218 GWh
Regulation Requirement*	943 MW	784 MW
RTO Primary Reserve Requirement	NA	2,063 MW
Total Billing	$22.12 Billion	$25.16 Billion
Peak	Jul 17, 2012 17:00	Jul 18, 2013 17:00
Peak Load	154,344 MW	157,508 MW
Load Factor	0.58	0.57
Installed Capacity	As of 9/30/2012	As of 9/30/2013
Installed Capacity	185,841 MW	185,085 MW

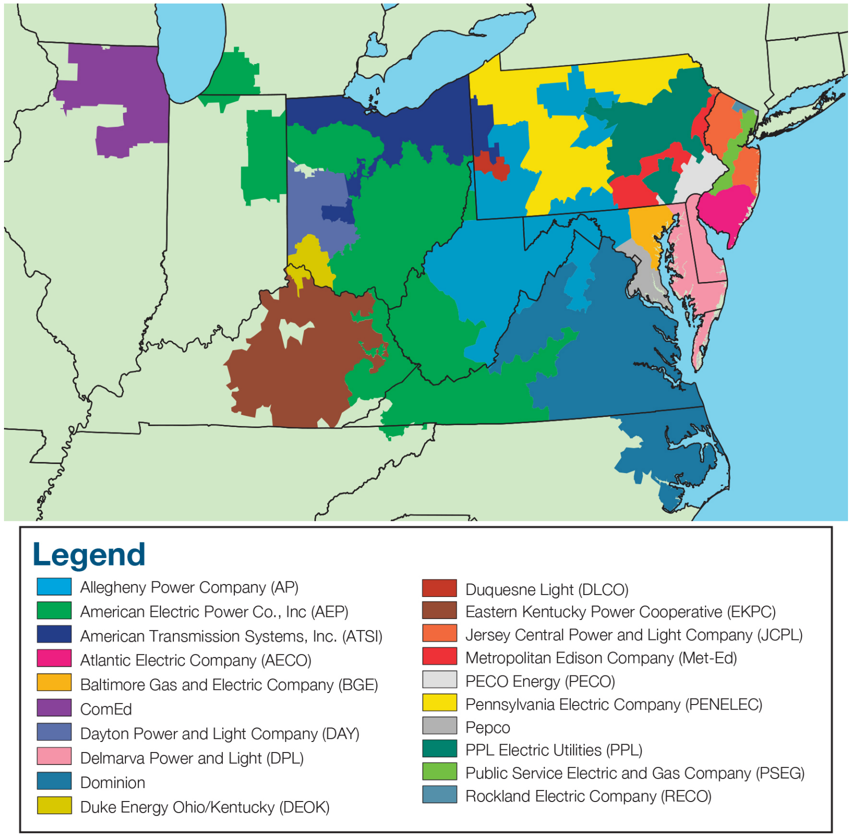
* Daily average

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2013, had installed generating capacity of 185,560 megawatts (MW) and 877 members including market buyers, sellers and traders of electricity in a region including more than 60 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1). [2,3,4] In the first nine months of 2013, PJM had total billings of $25.16 billion, up from $22.12 billion in the first nine months of 2012.[5] As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

1 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."
2 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2013. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.
5 Monthly billing values are provided by PJM.

Figure 1-1 PJM's footprint and its 20 control zones



PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Markets, the Day - Ahead Scheduling Reserve (DASR) Market and the Long Term, Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented an auction-based FTR Market on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008.[6,7]

On June 1, 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC).

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2013, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

For each PJM market, market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness

6 See also the *2012 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones." <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

7 Analysis of 2013 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined PJM. In January 2012, the Duke Energy Ohio/Kentucky Control Zone joined PJM. In June 2013, the Eastern Kentucky Power Cooperative (EKPC) joined PJM. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2013, see *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between ownership among multiple entities and the market demand and it does so using actual market conditions reflecting both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants, also sometimes referenced as participant conduct.

Market performance refers to the outcome of the market. Market performance reflects the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market performance, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

The MMU concludes the following for the first nine months of 2013:

Table 1-2 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1180 with a minimum of 871 and a maximum of 1610 in the first nine months of 2013.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive

behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[9]

Table 1-3 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.[10]

- 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.[11]

- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.

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

- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.

Table 1-4 The Regulation Market results were indeterminate for January through September, 2013

	January through September 2013	
Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	To Be Determined	To Be Determined

- The Regulation Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 91 percent of the hours in January through September, 2013.

8 OATT Attachment M.
9 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
10 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
11 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.

- Participant behavior in the Regulation Market was evaluated as competitive for January through September, 2013 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as indeterminate, after the introduction of the new market design. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design are inefficient and because there is not yet enough information on performance.
- Market design was evaluated as indeterminate, after the introduction of the new market design. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. The market design also includes the incorrect definition of the marginal benefits factor for purposes of settlement[12]. It is too early to reach a definitive conclusion about the new market design because there is not yet enough information about actual implementation of the design.

Table 1-5 The Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration. The MMU estimates that the Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 5.6 percent of the hours in January through September, 2013.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.
- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in competitive prices.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 1-6 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), 15 percent of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test, and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

12 On October 2, 2013 FERC issued an order directing PJM to compensate regulating resources (the portion of each resource's compensation based on performance) based on a mileage ratio multiplier. This ratio will be the hourly mileage of the RegD signal / mileage of the RegA signal. This ratio increases the regulation performance compensation paid to high performing resources compared with regular resources. Between October 2012 and September 2013 the average mileage ratio has been 3.11 compared to an average marginal benefit factor of 2.63. PJM will begin to settle the regulation market (performance segment) using the mileage ratio on November 1, 2013. PJM will then recalculate performance regulation settlement for the purpose of adjusting the credits from October 1, 2012, through October 31, 2013. The regulation performance clearing price will not change.

Table 1-7 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as mixed because while there are many positive features of the FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several features of the FTR design which result in underfunding and features of the FTR design which incorporate subsidies which also contribute to underfunding. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[13] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[14]

Reporting

The MMU performs its reporting function by issuing and filing annual and quarterly state of the market reports, and reports on market issues. The state of the market reports provide a comprehensive analysis of the structure, behavior and performance of PJM markets. The reports evaluate whether the market structure of each PJM Market is competitive or not competitive; whether participant behavior is competitive or not competitive; and, most importantly, whether the outcome of each market, the market performance, is competitive or not competitive. The MMU also evaluates the market design for each market. Market design translates participant behavior within the market structure into market performance. The MMU evaluates whether the market design of each PJM market provides the framework and incentives for competitive results. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

The MMU's quarterly state of the market reports supplement the annual state of the market report for the prior year, and extend the analysis into the current year. Readers of the quarterly state of the market reports should refer to the prior annual report for detailed explanation of reported metrics and market design.

The MMU's reports on market issues cover specific topics in depth. For example, the MMU issues reports on RPM auctions. In addition, the MMU's reports frequently respond to the needs of FERC, state regulators, or other authorities, in order to assist policy development, decision making in regulatory proceedings, and in support of investigations.

13 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

14 OATT Attachment M § IV; 18 CFR § 1c.2.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[15] The MMU has direct, confidential access to the FERC.[16] The MMU may also refer matters to the attention of state commissions.[17]

The MMU monitors market behavior for violations of FERC Market Rules.[18] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[19,20] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[21]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[22] If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[23,24] If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

Another important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price based or cost based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost based offer accurately reflects short run marginal cost. Cost based offers for the energy market and the regulation market are based on incremental costs as defined in the PJM Cost Development Guidelines (PJM Manual 15).[25] The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[26]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[27,28,29,30]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[31] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they

15 OATT Attachment M § IV.
16 OATT Attachment M § IV.K.3.
17 OATT Attachment M § IV.H.
18 OATT Attachment M § II(d)&(q) ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")
19 The FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.
20 OATT Attachment M § II(h-1).
21 OATT Attachment M § IV.C.
22 OATT Attachment M § IV.I.1.
23 *Id.*
24 *Id.*

25 See OATT Attachment M–Appendix § II.A.
26 OATT Attachment M–Appendix § II.E.
27 OATT Attachment M–Appendix § II.B.
28 OATT Attachment M–Appendix § II.C.
29 OATT Attachment M–Appendix § IV.
30 OATT Attachment M–Appendix § VII.
31 OATT Attachment M § IV.

may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[32] PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[33] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[34] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[35] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[36] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[37]

Prioritized Summary of New Recommendations

Table 1-8 includes a brief description and a priority ranking of the MMU's new recommendations for this quarterly report.

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects.

Table 1-8 Prioritized summary of new recommendations

Priority	Section	Description
Medium	4 - Operating Reserves	Reflect impact of all physical constraints in market prices.
High	5 - Capacity	Increase the Capacity Resource Deficiency Charge.
High	5 - Capacity	Require PJM to sell excess capacity, if necessary, in Incremental Auctions at the BRA clearing price.
High	5 - Capacity	Eliminate requirement for First and Second Incremental Auctions.
High	5 - Capacity	Define Market Seller Offer Cap for First and Second Incremental Auctions, if held, as higher of 1.0 times the Base Residual Auction clearing price or ACR.
High	5 - Capacity	Enforce the rules governing the requirement to be a physical resource for all resource types.
Low	6 - Demand Response	Adopt the ISO-NE demand response metering requirements.
Low	6 - Demand Response	The MMU recommends that demand resources be required to provide their nodal location.
Low	9 - Interchange Transactions	Align interface pricing definitions between PJM and MISO.
Medium	9 - Interchange Transactions	Eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.
Low	9 - Interchange Transactions	Eliminate the NIPSCO and Southeast interface pricing points.
High	10 - Ancillary Services	Eliminate rule paying for Tier 1 MW at Tier 2 clearing price when the non-synchronized reserve price is above $0.
High	13 - FTRs and ARRs	Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.

32 OATT § 12A.
33 OATT Attachment M § IV.D.
34 *Id.*
35 *Id.*
36 *Id.*
37 OATT Attachment M § VI.A.

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-9 provides the average price and total revenues paid, by component, for the first nine months of 2012 and 2013.

Table 1-9 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 94.6 percent of the total price per MWh in the first nine months of 2013.

Each of the components is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and non firm point to point transmission service.[38]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[39]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[40]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[41]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[42]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[43]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[44]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[45]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[46]
- The Black Start component is the average cost per MWh of black start service.[47]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[48]

38 OATT §§ 13.7, 14.5, 27A & 34.
39 OA Schedules 1 §§ 3.2.3 & 3.3.3.
40 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
41 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
42 OATT Schedule 12.
43 Reliability Assurance Agreement Schedule 8.1.
44 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
45 OATT Schedule 1A.
46 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
47 OATT Schedule 6A. The Black Start charges do not include Operating Reserve charges required for units to provide Black Start Service under the ALR option.
48 OATT Attachments H-13, H-14 and H-15 and Schedule 13.

- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[49]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[50]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[51]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[52]

Table 1-9 Total price per MWh by category: January through September 2012 and 2013

Category	Jan-Sep 2012 $/MWh	Jan-Sep 2013 $/MWh	Percent Change Totals	Jan-Sep 2012 Percent of Total	Jan-Sep 2013 Percent of Total
Load Weighted Energy	$35.02	$39.75	13.5%	71.4%	73.1%
Capacity	$6.27	$6.56	4.8%	12.8%	12.1%
Transmission Service Charges	$4.69	$5.09	8.4%	9.6%	9.4%
Reactive	$0.44	$0.69	57.0%	0.9%	1.3%
Operating Reserves (Uplift)	$0.75	$0.66	(12.0%)	1.5%	1.2%
PJM Administrative Fees	$0.44	$0.43	(0.8%)	0.9%	0.8%
Transmission Enhancement Cost Recovery	$0.32	$0.39	24.1%	0.6%	0.7%
Capacity (FRR)	$0.63	$0.12	(81.0%)	1.3%	0.2%
Regulation	$0.23	$0.27	16.7%	0.5%	0.5%
Black Start	$0.02	$0.14	491.5%	0.0%	0.3%
Transmission Owner (Schedule 1A)	$0.08	$0.08	(2.6%)	0.2%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.06	$0.08	23.5%	0.1%	0.1%
Synchronized Reserves	$0.03	$0.04	20.9%	0.1%	0.1%
NERC/RFC	$0.02	$0.02	(0.8%)	0.0%	0.0%
Load Response	$0.01	$0.01	30.3%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(0.2%)	0.0%	0.0%
Non-Synchronized Reserves	NA	$0.00	NA	NA	0.0%
Transmission Facility Charges	$0.00	$0.00	21.2%	0.0%	0.0%
Total	$49.03	$54.36	10.9%	100.0%	100.0%

49 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
50 OA Schedule 1 § 3.6.
51 OA Schedule 1 § 5.3b.
52 OA Schedule 1 § 3.2.3A.001.

Section Overviews

Overview: Section 3, "Energy Market"

Market Structure

- **Supply.** Average offered supply increased by 2,646, or 1.5 percent, from 173,414 MW in the first nine months of 2012 to 176,060 MW in the first nine months of 2013.[53] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 731 MW of new capacity were added to PJM. This new supply was partially offset by the deactivation of 7 units (476.9 MW) since January 1, 2013.
- **Demand.** The PJM system peak load for the first nine months of 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for the first nine months of 2012, which was 154,344 MW in the HE 1700 on July 17, 2012.[54]
- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.
- **Local Market Structure and Offer Capping for Energy.** PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first nine months of 2013. PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.1 percent in the first nine months of

53 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
54 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2012 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

2012 to 0.2 percent in the first nine months of 2013. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.1 percent in the first nine months of 2012 to 0.5 percent in the first nine months of 2013.

- **Reliability and Offer Capping.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.5 percent in the first nine months of 2012 to 3.0 percent in the first nine months of 2013. In the Real-Time Energy Market, for units committed to provide energy for reliability reasons, offer-capped unit hours increased from 0.2 percent in the first nine months of 2012 to 3.8 percent in the first nine months of 2013.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 81 units eligible for FMU or AU status in at least one month during the first nine months of 2013, 24 units (29.6 percent) were FMUs or AUs for all nine months, and 16 units (19.8 percent) qualified in only one month of 2013.

- **Local Market Structure.** In the first nine months of 2013, 10 Control Zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Market Performance: Markup, Load, Generation and LMP

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer.

  In the first nine months of 2013, the unadjusted markup was negative, -$1.21 per MWh, primarily as a result of competitive behavior by coal units and the competitive removal of the 10 percent adder. The adjusted markup was positive, $0.27 per MWh or 0.7 percent of the PJM real-time, load-weighted average LMP.

  The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** PJM average real-time load in the first nine months of 2013 increased by 0.5 percent from the first nine months of 2012, from 88,687 MW to 89,123 MW. The PJM average real-time load in 2013 would have decreased by 0.2 percent from the first nine months of 2012, from 88,687 MW to 88,522 MW, if the EKPC Transmission Zone had not been included in this comparison for the months prior to its integration to PJM.[55]

  PJM average day-ahead load in the first nine months of 2013, including DECs and up-to congestion transactions, increased by 9.5 percent from the first nine months of 2012, from 132,494 MW to 145,139 MW. The PJM average day-ahead load, including DECs and up-to congestion transactions, would have increased 9.1 percent from the first nine months of 2012, from 132,494 MW to 144,501 MW, if the EKPC Transmission Zone had not been included. The day-ahead load growth was 1,800.0 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

55 The EKPC zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

- **Generation.** PJM average real-time generation in the first nine months of 2013 increased by 0.1 percent from the first nine months of 2012, from 90,367 MW to 90,432 MW. The PJM average real-time generation in the first nine months of 2013 would have decreased by 0.5 percent from the first nine months of 2012, from 90,367 MW to 89,910 MW, if the EKPC Transmission Zone had not been included.

  PJM average day-ahead generation in the first nine months of 2013, including INCs and up-to congestion transactions, increased by 9.8 percent from the first nine months of 2012, from 135,213 MW to 148,489 MW. The PJM average day-ahead generation, including INCs and up-to congestion transactions, would have increased by 9.4 percent from the first nine months of 2012, from 135,213 MW to 147,895 MW, if the EKPC Transmission Zone had not been included. The day-ahead generation growth was 9,700.0 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Generation Fuel Mix.** During the first nine months of 2013, coal units provided 44.5 percent, nuclear units 34.5 percent and gas units 16.5 percent of total generation. Compared to the first nine months of 2012, generation from coal units increased 6.2 percent, generation from nuclear units increased 0.9 percent, and generation from gas units decreased 16.1 percent. This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first nine months of 2013, particularly in eastern zones, and lower or constant coal prices.

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect the changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion.

  PJM Real-Time Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 15.0 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.30 per MWh versus $32.45 per MWh. The load-weighted average LMP was 13.5 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.75 per MWh versus $35.02 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 16.6 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.50 per MWh versus $32.16 per MWh. The load-weighted average LMP was 15.1 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.49 per MWh versus $34.29 per MWh.[56]

- **Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. For the first nine months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 24.1 percent by spot market purchases and 65.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot market purchases increased by 0.9 percentage points and reliance on self-supply decreased by 2.3 percentage points. For the first nine months of 2013, 7.5 percent of day-ahead load was supplied by bilateral contracts, 23.4 percent by spot market purchases, and 69.1 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot market purchases increased by 1.1 percentage points, and reliance on self-supply decreased by 1.9 percentage points.

Scarcity

- **Scarcity Pricing Events in 2013.** PJM's market did not experience any reserve-based scarcity events in the first nine months of 2013.

56 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

Section 3 Recommendations

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[57] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[58]
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007 and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders are no longer required to serve the purpose for which they were created, and the adders now interfere with the efficient operation of PJM markets. This recommendation is currently scheduled to be evaluated through the PJM stakeholder process in the fourth quarter of 2013.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during Maximum Emergency Events.[59]

57 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 22 (February 28, 2013).

58 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

Section 3 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first nine months of 2013, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Average real-time supply offered increased by 2,646 MW in the first nine months of 2013 compared to the first nine months of 2012, while peak load increased by 3,165 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices

59 PJM Tariff, 6A.1.3 Maximum Emergency p. 1645, 1699-1700.

within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first nine months of 2013 generally reflected supply-demand fundamentals.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[60] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented new scarcity pricing rules in 2012. There are significant issues with the scarcity pricing true up mechanism in the new PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2013.

Overview: Section 4, "Operating Reserve"

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges increased by 33.7 percent in the first nine months of 2013 compared to the first nine months of 2012, to a total of $652.9 million.

  Day-ahead operating reserve charges were 11.3 percent, balancing operating reserve charges were 48.3 percent, reactive services charges were 29.8 percent, synchronous condensing charges were 0.06 percent and black start services charges were 10.6 percent of total operating reserve charges in 2013.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.086 per MWh. The day-ahead operating reserve rate including

60 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

unallocated congestion charges averaged $0.118 per MWh. The balancing operating reserve reliability rates averaged $0.052, $0.031 and $0.004 per MWh for the RTO, Eastern and Western Regions. The balancing operating reserve deviation rates averaged $0.886, $2.193 and $0.118 per MWh for the RTO, Eastern and Western Regions. The lost opportunity cost rate averaged $0.861 per MWh and the canceled resources rate averaged $0.001 per MWh.

- **Reactive Service Rates.** The DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $1.952, $1.557 and $0.631 per MWh. The reactive transfer interface support rate averaged $0.141 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 46.7 percent of all day-ahead generator credits and 52.6 percent of all balancing generator credits. Combustion turbines and diesels received 73.7 percent of the lost opportunity cost credits. Combined cycles and coal units received 91.4 percent of all reactive services credits.
- **Economic and Noneconomic Generation.** In the first nine months of 2013, 81.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.1 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In the first nine months of 2013, 81.6 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 6.1 percent by transactions at hubs and aggregates and 12.3 percent by transactions at interfaces.
- Generators in the Eastern Region paid 15.0 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 75.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 13.9 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 24.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators paid 9.8 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.96 percent of all credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 34.5 percent of all credits. The top 10 organizations received 86.1 percent of all credits. Concentration indexes for the three largest operating reserve categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5343, balancing operating reserves HHI was 3927 and lost opportunity cost HHI was 4699.
- **Day-Ahead Unit Commitment for Reliability:** In the first nine months of 2013, 4.7 percent of the total day-ahead generation was scheduled as must run by PJM, of which 65.4 percent was made whole.
- **Lost Opportunity Cost Credits:** In the first nine months of 2013, lost opportunity cost credits decreased by $66.0 million compared to the first nine months of 2012. In the first nine months of 2013, the top three control zones receiving lost opportunity cost credits, AEP, ComEd and Dominion accounted for 60.7 percent of all lost opportunity cost credits, 53.6 percent of the credits for day-ahead generation from pool-scheduled combustion turbines and diesels, 57.6 percent of the credits for day-ahead generation not called in real time by PJM from those unit types and 53.9 percent of the credits day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Lost Opportunity Cost Calculation:** In the first nine months of 2013, lost opportunity cost credits would have been reduced by an additional $21.3 million, or 26.1 percent, if all changes proposed by the MMU had been implemented.

- **Black Start Service Units:** Certain units located in the AEP zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In the first nine months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $68.7 million.
- **Con Edison – PSEG Wheeling Contracts Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing operating reserves credits.
- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to operating reserve charges proposed by the MMU on operating reserve charge rates would be significant. For example, in the first nine months of 2013, the average rate paid by a DEC in the Eastern Region would have been $0.218 per MWh, which is $3.564 per MWh, 94.2 percent, less than the actual average rate paid.

Section 4 Recommendations

- The MMU recommends that the impact of physical constraints of all types be reflected in market prices to the maximum extent possible, reducing the necessity for out of market operating reserve payments and improving the efficiency of market prices.
- The MMU recommends the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.
- The MMU recommends four modifications to the energy lost opportunity cost calculations.
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with operating reserve credits calculation.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by location and the detailed reasons for the level of operating reserve payments by location in the PJM region.

Section 4 Conclusion

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy

Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters, the details of the rules which define payments and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. But these costs are collected as operating reserves rather than reflected in price as a result of the rules governing the determination of LMP in situations where something other than a simple thermal transmission constraint affects unit dispatch.

PJM has improved its oversight of operating reserves and continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels. However, given the impact of operating reserve charges on market participants, particularly virtual market participants, the MMU recommends that PJM take another step towards more precise definition and clearly identify and classify all reasons for incurring operating reserve charges in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The MMU recommends that the goal should be to have dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommended and supports PJM in the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.[61] For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.

Overall, the MMU recommends that the goal be to minimize the total level of operating reserve credits paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The goal should be to minimize the total incurred operating reserve charges and to increase the transactions over which those charges are spread in order to reduce the impact of operating reserve charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with operating reserve charges and to reduce the impact of operating reserve charges on decisions about how and when to participate in PJM markets.

61 PJM presented a problem statement at the Markets and Reliability Committee (MRC) to perform a holistic review of operating reserves. See "Item 10 – Operating Reserves Problem Statement," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130425/20130425-item-10-operating-reserves-problem-statement.ashx> (Accessed April 26, 2013).

Overview: Section 5, "Capacity Market"

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.[62]

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.[63] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[64] 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.[65]

RPM prices are locational and may vary depending on transmission constraints.[66] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand-side resources and Energy Efficiency resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During the period January 1 through September 30, 2013, PJM installed capacity increased 3,073.8 MW or 1.7 percent from 182,011.1 MW on January 1 to 185,084.9 MW on September 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 September 30, 2013, 41.9 percent was coal; 28.9 percent was gas; 17.9 percent was nuclear; 6.1 percent was oil; 4.4 percent was hydroelectric; 0.4 percent was solid waste; 0.5 percent was wind, and 0.0 percent was solar.
- **Market Concentration.** In the 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test. The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[67,68,69]

62 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2013 Quarterly State of the Market Report for PJM*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
63 See 126 FERC ¶ 61,275 (2009) at P 86.
64 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
65 See 126 FERC ¶ 61,275 (2009) at P 88.
66 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.
67 See OATT Attachment DD § 6.5.
68 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.
69 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

- **Imports and Exports.** Of the 7,493.7 MW of imports offered in the 2016/2017 RPM Base Residual Auction, 7,482.7 MW cleared. Of the cleared imports, 4,723.1 MW (63.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 8,490.0 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (3,193.8 MW).

Market Conduct

- **2014/2015 RPM Second Incremental Auction.** Of the 221 generation resources which submitted offers, unit-specific offer caps were calculated for six generation resources (2.7 percent). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First Incremental Auction were conducted in the third quarter of 2013. In the 2014/2015 RPM Second Incremental Auction, the RTO clearing price for Annual Resources was $25.00 per MW-day. The weighted average capacity price for the 2014/2015 Delivery Year is $127.74, including all RPM Auctions for the 2014/2015 Delivery Year held through the first nine months of 2013. In the 2015/2016 First Incremental Auction, the RTO clearing price for Annual Resources was $43.00 per MW-day. The weighted average capacity price for the 2015/2016 Delivery Year is $160.03, including all RPM Auctions for the 2015/2016 Delivery Year held through the first nine months of 2013.
- The delivery year weighted average capacity price was $75.08 per MW-day in 2012/2013 and $116.55 per MW-day in 2013/2014.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for January through September was 8.0 percent, an increase from the 7.5 percent average PJM EFORd for 2012.[70]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for January through September was 84.2 percent, a slight increase from the 84.1 percent PJM aggregate equivalent availability factor for 2012.
- **Outages Deemed Outside Management Control (OMC).** In the first nine months of 2013, 34.3 percent of forced outages were classified as OMC outages. 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.

Section 5 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 nine months of 2013. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in

70 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM Generator Availability Data Systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM. Data is for the twelve months ending December 31 or the nine months ending September 30, as downloaded from the PJM GADS database on October 22, 2013. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first nine months of 2013.[71]

Overview: Section 6, "Demand Response"

- **Demand Response Activity.** In the first nine months of 2013, total load reduction under the Economic Load Response Program decreased by 7,002 MWh compared to the same period in 2012, from 121,381 MWh in the first nine months of 2012 to 114,379 MWh in the first nine months of 2013, a six percent decrease. Total credits under the Economic Program decreased by $1,084,448, from $8,172,654 in the first nine months of 2012 to $7,088,205 in the same period of 2013, a 13 percent decrease. September credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day.

  The capacity market is the primary source of revenue to participants in PJM demand side programs. In the first nine months of 2013, Load Management (LM) Program revenue increased $33.8 million, or 12.8 percent, compared to the same period of 2012, from $263.6 million to $297.4 million in 2013.

  In the first nine months of 2013, Synchronized Reserve credits for demand side resources decreased by $1.9 million, or 54.2 percent, compared to the same period in 2012, from $3.6 million to $1.6 million in 2013.

- **Locational Dispatch of Demand-Side Resources.** PJM dispatches demand-side resources on a subzonal basis when appropriate, but only on a voluntary basis. Beginning with the 14/15 Delivery Year, demand resources will be dispatchable on a subzonal basis, defined by zip codes. More locational deployment of demand-side resources improves efficiency in a nodal market.

- **Load Management Product.** The load management product is currently defined as an emergency product. The load management product is an economic product and should be treated as an economic product in the PJM market design and in PJM dispatch. Demand resources should be called when the resources are required and prior to the declaration of an emergency. The MMU recommends that the DR program be classified as an economic program and not an emergency program.

- **Emergency Event Day Analysis.** Load management event rules allow over compliance to be reported when there is no actual over compliance. Settlement MWh are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero even if load actually increases. Considering all and only reported values, the observed load reduction of the five events in 2013 should have been 5,116.9 MW, rather than the 5,644.7 MW reported. Overall, compliance decreases from the reported 100.5 percent to 90.6 percent. This does not include locations that did not report their load during the emergency event days.

Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

71 For more complete conclusions, see *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market."

The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.

The MMU recommends that demand side measurement and verification be further modified to more accurately reflect compliance. Increases in load by load management resources during event hours should not be considered zero response or ignored, but should be included for reporting and determining compliance. Load management testing does not adequately reflect actual resource performance during event days. Testing should be initiated by PJM with limited warning to CSPs in order to more accurately reflect the conditions of an emergency event.[72] The MMU recommends that load management resources whose load drop method is designated as "Other" explicitly record the method of load drop.

The load management product is currently defined as an emergency product. In fact, the load management product is an economic product and it is treated as an economic product in the PJM capacity market design where it competes directly with generation capacity, affects market clearing prices and receives the market clearing price. The load management product should also be treated as an economic product in PJM dispatch meaning that demand resources should be called when the resources are required and prior to the declaration of an emergency. For these reasons, the MMU recommends that the DR program be classified as an economic program and not an emergency program.[73]

More locational deployment of Load Management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Along with the removal of load increases from compliance, non-reporting can cause an overstatement of load reductions of the reported load at a node. The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations. Negative event performance of a portfolio should be netted against the positive performance of other resources. Reported compliance should include those locations that increased load in addition to those that reduced load during an emergency event. The MMU also recommends that PJM adopt the ISO-NE metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to DR resources are based on actual metered data.[74]

Overview: Section 7, "Net Revenue"

Net Revenue

- In the first nine months of 2013, average energy market net revenues for a new entrant CT were three percent greater than in the first nine months of 2012.
- In the first nine months of 2013, average energy market net revenues for a new entrant CC were 15 percent less than in 2012.
- In the first nine months of 2013, average energy market net revenues for a new entrant coal plant were 133 percent greater than in the first nine months of 2012. This increase in net revenues was a result of the change in the relative prices of coal and gas and higher energy market prices.
- In the first nine months of 2013, average energy market net revenues for a new entrant wind plant were 15 percent greater than in the first nine months of 2012.
- In the first nine months of 2013, average energy market net revenues for a new entrant solar plant were 40 percent greater than in the first nine months of 2012.

Section 7 Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced

72 For additional conclusions see the *2012 State of the Market Report for PJM*, Volume 2: Section 5, "Demand Response."
73 This issue is currently being discussed in the Capacity Senior Task Force (CSTF) with an expected resolution by summer 2014.

74 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response" <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed November 11, 2013) ISO-NE requires that DR resource have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, Demand Response resources in ISO-NE must also be registered at a single node.

through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units.

Overview: Section 8, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[75] On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[76] The rule establishes a compliance deadline of April 16, 2015.

  In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter. On March 28, 2013, EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[77]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). The CAA requires each State to prohibit emissions that significantly interfere with the ability of another State to meet NAAQS.

  On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated the most recently issued rule limiting interstate emissions, the Cross-State Air Pollution Rule (CSAPR), which previously had been subject to a stay.[78] The Supreme Court granted EPA's petition for certiorari on June 24, 2013, and its review of CSAPR is pending. Meanwhile, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion

75 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

76 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

77 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

78 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

engines (RICE).[79] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[80] The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO2/MWh gross over an 84 operating month (7-year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[81]

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[82] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[83]

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2013 for the 2012-2014 compliance period were an average of $2.89 per ton, above the price floor for 2013. The clearing price is equivalent to a price of $3.19 per metric tonne, the unit used in other carbon markets.

Emissions Controls in PJM Markets

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. On June 30, 2013, 69.4 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 97.6 percent of coal steam MW had some type of particulate control, and 91.3 percent of fossil fuel fired capacity in PJM had NO_x emission control technology in place.

State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of September 30, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

79 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).
80 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Propose Rule, EPA-HQ-OAR-2013-0495.
81 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660 (September 20, 2013).
82 N.J.A.C. § 7:27-19.
83 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

Renewable energy credits provide out of market payments to qualifying resources, primarily wind and solar. The out of market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the LMP is equal to the marginal cost of producing minus the credit received for each MWh. As the net of LMP and credits can be negative, the credits can provide an incentive to make negative energy offers. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the Federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Overview: Section 9, "Interchange Transactions"

Interchange Transaction Activity

- **East Kentucky Power Cooperative (EKPC).** On June 1, 2013, East Kentucky Power Cooperative was integrated into PJM. This integration eliminated the EKPC Interface. The integration did not result in any changes to interface pricing points.
- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first nine months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in January through August, and a net exporter of energy in September.[84] During the first nine months of 2013, the real-time net interchange of 4,706.7 GWh was greater than net interchange of 2,152.5 GWh in the first nine months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first nine months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. During the first nine months of 2013, the total day-ahead net interchange of -12,727.7 GWh was greater than net interchange of -5,824.8 GWh during the first nine months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2013, gross imports in the Day-Ahead Energy Market were 150.8 percent of gross imports in the Real-Time Energy Market (403.2 percent during the first nine months of 2012), gross exports in the Day-Ahead Energy Market were 218.5 percent of the gross exports in the Real-Time Energy Market (447.5 percent during the first nine months of 2012).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at eleven of PJM's 17 interface pricing points eligible for real-time transactions.[85]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months

84 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
85 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

of 2013, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead.

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first nine months of 2013, up-to congestion transactions had net exports at seven of PJM's 19 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in 47.0 percent of hours in the first nine months of 2013.

- **PJM and New York ISO Interface Prices.** In the first nine months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 53.1 percent of the hours in the first nine months of 2013.

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[86] The average hourly flow during the first nine months of 2013 was -354 MW.[87] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 69.5 percent of the hours in the first nine months of 2013.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[88] The average hourly flow during the first nine months of 2013 was -127 MW.[89] The direction of flows was consistent with price differentials in 65.8 percent of the hours in the first nine months of 2013.

- **Hudson DC Line.** The Hudson direct current (DC) line began commercial operation on June 3, 2013. The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM and NYISO. While the Hudson DC line is a bidirectional line, power flows will only be from PJM to New York. In the first four months of operations, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus.[90] The average hourly flow during the first four months of operation was -22 MW.[91] The direction of flows was consistent with price differentials in 60.9 percent of the hours between June 3, 2013 and September 30, 2013.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at one or more specific interfaces.

  For the first nine months of 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh. For the first nine months of 2012, net scheduled interchange was 1,051 GWh and net actual interchange was 801 GWh, a difference of 251 GWh. This difference is inadvertent interchange.

86 In the first nine months of 2013, there were 1,128 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $42.62 while the NYISO LMP at the Neptune Bus during non-zero flows was $64.19, a difference of $21.57.

87 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -428 MW.

88 In the first nine months of 2013, there were 1,351 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $41.23 while the NYISO LMP at the Neptune Bus during non-zero flows was $48.95, a difference of $7.72.

89 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Linden VFT line was -161 MW.

90 In its four months of operation, there were 2,987 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $48.65 while the NYISO LMP at the Hudson Bus during non-zero flows was $55.00, a difference of $6.35.

91 The average hourly flow during the first four months of operations, ignoring hours with no flow, on the Hudson line was -120 MW.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 45 TLRs of level 3a or higher in the first nine months of 2013, compared to 29 TLRs issued in the first nine months of 2012.
- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 105,472 bids per day, with an average cleared volume of 1,221,114 MWh per day, in the first nine months of 2013, compared to an average of 58,273 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012.
- **Elimination of Ontario Interface Pricing Point.** The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing. Because 5,000 GWh of the 5,023 GWh of the net scheduled transactions between PJM and IESO wheeled through MISO during the first nine months of 2013, the MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority until the stakeholder process determines an alternative approach to pricing these transactions.
- **PJM and NYISO Coordinated Interchange Transaction Proposal.** The Coordinated Transaction Scheduling (CTS) proposal provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated. The evaluation will be based on the forward-looking prices as determined by PJM's Intermediate Term Security Constrained Economic Dispatch tool (ITSCED) and the NYISO's Real Time Commitment (RTC) tool.

  CTS transactions are evaluated based on the spread bid, which limits the amount price convergence that can occur. As long as balancing operating reserve payments are applied and CTS transactions are optional, there is no reason not to proceed with the development of the CTS proposal. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be addressed to improve the efficiency of interchange transaction pricing at the PJM/NYISO seam. Minimizing this time lag is more likely to improve pricing efficiency at the PJM/NYISO border than the CTS transaction approach.
- **Elimination of Sources and Sinks.** The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[92] On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.
- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction. The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The MMU continues to recommend that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non-

92 See "Meeting Minutes, "Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> (Accessed October 9, 2013).

market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non-market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non-market areas do not include these features. The market areas are extremely transparent and the non-market areas are not transparent.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first nine months of 2013, including evolving transaction patterns, economics and issues. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows began to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased, reducing the day-ahead gross import and export volumes. While the gross import and export volumes in the Day-Ahead Market have decreased, the net direction of power flows has remained predominantly in the export direction.

In the first nine months of 2013, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for 53.0 percent of the hours for transactions between PJM and MISO and for 46.9 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by relying on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely as possible to the expected actual power flows would result in a more economic dispatch of the entire Eastern Interconnection.

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load which can create loop flows and inaccurate pricing for transactions. The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create business rules that prevent sham scheduling among and between the RTO/ISO markets.

The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the operation of the PJM Day-Ahead Market and charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges. The level of the fee should be determined based on the method defined in the State of the Market Report.[93]

There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast). The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the integration, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO. The NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy market to facilitate the long term day-ahead positions created at the NIPSCO interface prior to the integration.

93 See the *2013 Quarterly State of the Market Report for PJM: January through September,* Section 4, "Operating Reserves."

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[94] After the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. The grandfathered agreements for the Southeast interface pricing point have expired. The Southeast interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy market to facilitate the long term day-ahead positions created prior to the consolidation of the Southeast and Southwest interface pricing points.

The MMU recommends that PJM no longer accept long term positions of any kind at the NIPSCO and Southeast interface pricing points and to eliminate these interface pricing points from the Day-Ahead and Real-Time Energy Markets.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[95] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

The MMU continues to recommend that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

94 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (Accessed October 10, 2013).
95 See Docket Nos. ER12-1338-000 and ER12-1343-000.

Overview: Section 10, "Ancillary Services"

Regulation Market

The PJM Regulation Market continues to be operated as a single market.

Market Structure

- **Supply.** In January through September 2013, the supply of offered and eligible regulation in PJM was both stable and adequate. The ratio of offered and eligible regulation to regulation required averaged 3.67. This is a 14.7 percent increase over January through September 2012 when the ratio was 3.20.
- **Demand.** The on-peak regulation requirement is equal to 0.70 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 0.70 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in January through September, 2013, was 784 MW. This is a 214 MW decrease in the average hourly regulation demand of 998 MW in the same period of 2012.
- **Market Concentration.** In January through September 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 2063 which is classified as highly concentrated.[96] In January through September 2013, 91 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (44 percent of hours failed the three pivotal supplier test in January through September 2012).

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. The performance offer is converted to $/MW by multiplying the MW offer by the ΔMW/MW value of the signal type of the unit. Owners must also specify which signal type the unit will be following, RegA or RegD.[97] As of September 30, 2013, there were 22 resources offering performance regulation and following the RegD signal.
- **Price and Cost.** The weighted average Regulation Market Clearing Price for the PJM Regulation Market for January through September 2013 was $32.72. This is an increase of $17.80, or 119.3 percent, from the weighted average price for regulation in January through September 2012. The cost of regulation from January through September 2013 was $37.35. This is a $16.77 (81.5 percent) increase from the same time period in 2012.

Synchronized Reserve Market

Although PJM has retained the two synchronized reserve markets it implemented on February 1, 2007, their definition has changed. The RFC Synchronized Reserve Zone has incorporated the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated the Dominion Zone to become the Mid-Atlantic Dominion Reserve Zone. PJM has the right to define new zones or subzones "as needed for system reliability."[98]

Market Structure

- **Supply.** In January through September, 2013, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of Demand Response (DR) to the Synchronized Reserve Market remains significant. Demand resources are relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices.
- **Demand.** PJM made a minor change to the default hourly required synchronized reserve requirements on October 1, 2012. When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Subzone became the Mid-Atlantic Dominion Subzone on October 1, 2012, the requirement remained at 1,300 MW. The integration

96 See the *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

97 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

98 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 61 (June 27, 2013), p. 66.

of East Kentucky Power Cooperative (EKPC) into PJM on June 1, 2013, had no impact on the Synchronized Reserve Market requirement because the largest contingencies remain in the Mid-Atlantic Dominion Subzone. The EKPC integration did, however, increase the availability of both Tier 1 and Tier 2 MW available throughout the RTO.

In early June 2013, PJM implemented a modification to the way the transfer interface defines the Mid-Atlantic Dominion Subzone within the RTO Zone. The change makes calculations of the unit distribution factor (DFAX) values across the interface consistent with the way these values are calculated in the energy market. Additionally, PJM calculates the most limiting interface in real time for each market optimization, ASO, IT-SCED and RT-SCED. For most hours it is Bedington – Black Oak. The second most common limiting interface is AP South.

- **Market Concentration.** For January through September 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4372 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through September, 2012, was 3202, which is classified as "highly concentrated."[99] In January through September, 2013, 58 percent of hours had a maximum market share greater than 40 percent, compared to 45 percent of hours in January through September, 2012.

  In the Mid-Atlantic Dominion Subzone, in January through September, 2013, the MMU estimates that 5.6 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In January through September, 2012, the MMU estimates that 24 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Dominion Subzone Synchronized Reserve Market in January through September 2013 was characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was $6.86 per MW in January through September, 2013, a decrease of three percent over January through September 2012. The total cost of synchronized reserves per MW in January through September 2013 was $14.82, a 35 percent increase from the $10.92 cost of synchronized reserve in January through September 2012. The market clearing price was 51 percent of the total synchronized reserve cost per MW in January through September 2013, down from 64 percent in January through September 2012.
- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in January through September period of 2013. Although supplies were always adequate to meet demand, an extended spinning event on September 10 raised concerns that the current method for estimating Tier 1 is incorrect. PJM has initiated studies designed to improve the accuracy of Tier 1 estimation. It is expected that by January 1, 2014, the amount of Tier 1 estimated, especially during periods of high demand, will decrease as a result of changes to the estimation method.

99 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

DASR

The purpose of the DASR Market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[100] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The MMU calculates that in January through September, 2013, zero hours in the DASR market would have failed the three pivotal supplier test. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.
- **Demand.** In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero, but there is an opportunity cost associated with providing DASR. As of September 30, 2013, 15 percent of offers reflected economic withholding. PJM rules require that all units with reserve capability that can be converted into energy within 30 minutes offer into the DASR Market.[101] Units that do not offer have their offers set to zero.
- **DR.** Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through September, 2013.

100 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.
101 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 144.

Market Performance

- **Price.** The weighted DASR market clearing price in January through September 2013 was $0.93 per MW. In January through September 2012, the weighted price of DASR was $0.75 per MW.

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[102]

In January through September 2013 black start charges were $80.3 million. Black start zonal charges in January through September 2013 ranged from $0.03 per MW-day in the ATSI zone (total charges were $95,492) to $10.30 per MW-day in the AEP zone (total charges were $65,557,476). For each zone, Table 10-23. shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.08 per MW.

Section 10 Conclusion

The design of the Regulation Market changed significantly effective October 1, 2012. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about performance under the new market design because there is not yet enough information on performance. It is essential that the Regulation Market incorporate the consistent implementation of the marginal benefit factor in optimization, pricing and settlement. But the experience of the last quarter of 2012 and the first three quarters of 2013 is cause for optimism with respect the performance of the Regulation Market under the new market design.

102 OATT Schedule 1 § 1.3BB.

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The MMU concludes that the structure of the DASR Market was competitive in the first nine months of 2013, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

Overall, the MMU concludes that it is not yet possible to reach a definitive conclusion about the new Regulation Market design, but there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in the first nine months of 2013. The MMU concludes that the DASR Market results were competitive in the first nine months of 2013.

Overview: Section 11, "Congestion and Marginal Losses"

Energy Cost

- **Total Energy Costs.** Total energy costs in the first nine months of 2013 decreased by $85 million or 19.2 percent from the first nine months of 2012, from -$442.6 million to -$527.6 million. Day-ahead net energy costs in the first nine months of 2013 decreased by $171.9 million or 40.0 percent from the first nine months of 2012, from -$429.8 million to -$601.6 million. Balancing net energy costs in the first nine months of 2013 increased by $98.9 million or 478.0 percent from the first nine months of 2012, from -$20.7 million to $78.2 million.
- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in the first nine months of 2013 ranged from -$90.8 million in July to -$46.5 million in April.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first nine months of 2013 increased by $39.4 million or 5.2 percent from the first nine months of 2012, from $757.6 million to $796.9 million. Day-ahead net marginal loss costs in the first nine months of 2013 increased by $95.5 million or 12.3 percent from the first nine months of 2012, from $776.0 million to $871.5 million. Balancing net marginal loss costs decreased in the first nine months of 2013 by $56.1 million or 303.8 percent from the first nine months of 2012, from -$18.5 million to -$74.6 million.
- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in the first nine months of 2013 ranged from $66.2 million in April to $142.1 million in July.

- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and netresidual market adjustments, which is paid back in full to load and exports on a load ratio basis.[103] The marginal loss credits decreased in the first nine months of 2013 by $46.0 million or 14.7 percent from the first nine months of 2012, from $313.3 million to $267.3 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $83.5 million or 19.6 percent, from $425.2 million in the first nine months of 2012 to $508.7 million in the first nine months of 2013.[104]
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $197.3 million or 32.7 percent, from $603.2 million in the first nine months of 2012 to $800.5 million in the first nine months of 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $113.8 million or 63.9 percent from -$178.0 million in the first nine months of 2012 to -$291.8 million in the first nine months of 2013.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2013 ranged from $27.8 million in March to $109.2 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the West interface, the ATSI interface, the Bridgewater - Middlesex line, the Cloverdale transformer.

103 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60 (June 1, 2013). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

104 The total zonal congestion numbers were calculated as of October 14, 2013, and are based on continued PJM billing updates, subject to change.

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first nine months of 2013. Day-ahead congestion frequency increased by 54.1 percent from 168,509 congestion event hours in the first nine months of 2012 to 259,605 congestion event hours in the first nine months of 2013. Day-ahead, congestion-event hours increased on all types of congestion facilities.

  Real-time congestion frequency decreased by 6.0 percent from 15,153 congestion event hours in the first nine months of 2012 to 14,249 congestion event hours in the first nine months of 2013. Real-time, congestion-event hours increased on the interfaces and the flowgates, while congestion on the transformers, and the transmission lines decreased.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first nine months of 2013, for only 2.0 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first nine months of 2013, for 37.9 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

  The AP South Interface was the largest contributor to congestion costs in the first nine months of 2013. With $144.1 million in total congestion costs, it accounted for 28.3 percent of the total PJM congestion costs in the first nine months of 2013. The top five constraints in terms of congestion costs together contributed $183.8 million, or 36.1 percent, of the total PJM congestion costs in the first nine months of 2013. The top five constraints were the AP South interface, the West interface, the ATSI interface, the Bridgewater – Middlesex line, and the Cloverdale transformer.
- **Zonal Congestion.** ComEd was the most congested zone in the first nine months of 2013. ComEd had -$337.8 million in total load costs, -$472.5 million in total generation credits and -$14.1 million in explicit congestion, resulting in $120.5 million in net congestion costs, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The

Nelson – Cordova line, the Byron - Cherry Valle flowgate, the AP South interface, the Braidwood transformer, and the Crete - St Johns Tap flowgate contributed $44.1 million, or 36.6 percent of the total ComEd Control Zone congestion costs.

The AEP Control Zone was the second most congested zone in PJM in the first nine months of 2013, with $76.5 million. The AP South interface contributed $20.0 million or 27.4 percent of the total AP Control Zone congestion cost in first nine months of 2013. The AP Control Zone was the third most congested zone in PJM in the first nine months of 2013, with a cost of $74.3 million.

- **Ownership.** In the first nine months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first nine months of 2013, financial companies received $84.1 million in net congestion credits, an increase of $16.8 million or 25.0 percent compared to the first nine months of 2012. In the first nine months of 2013, physical companies paid $592.8 million in net congestion charges, an increase of $100.3 million or 20.4 percent compared to the first nine months of 2012.

Section 11 Conclusion

Energy costs are the incremental costs to the system, which are the same at every bus for each hour, without taking losses and congestion into account.

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Marginal loss costs had been decreasing since 2010, due to decreases in LMP and fuel costs. However, increases in the LMP and fuel costs have led to higher marginal loss costs in the first nine months of 2013 compared to the first nine months of 2012. Total marginal loss costs increased in the first nine months of 2013 by $39.4 million or 5.2 percent from the first nine months of 2012, from $757.6 million to $796.9 million.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities and the geographic distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 85.5 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs. FTRs were paid at 67.8 percent of the target allocation level for the 2012 to 2013 planning period, and at 77.3 percent of the target allocation level for the 2013 to 2014 planning period through September 30, 2013.[105] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

Overview: Section 12, "Planning"

Planned Generation and Retirements

- **Planned Generation.** At September 30, 2013, 63,765 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,000 MW in the first nine months of 2013. Wind projects account for 16,442 MW of nameplate capacity or 25.7 percent of the capacity in the queues and combined-cycle projects account for 37,634 MW of capacity or 59.0 percent of the capacity in the queues.
- **Generation Retirements.** There are 22,070.4 MW planned to be retired between 2011 and 2019, with all but 614.5 MW retired by June, 2015. The AEP zone accounts for 3,560 MW, or 32.7 percent of all MW planned for deactivation from 2013 through 2019. Since January 1, 2013, 1,437 MW that were scheduled to be deactivated have withdrawn their deactivation notices, and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI zone.

105 See the *2012 State of the Market Report for PJM, Volume II:* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014."

- **Generation Mix.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the Eastern MAAC (EMAAC) and Southwestern MAAC (SWMAAC) locational deliverability areas (LDAs), the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity.[106] Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, despite retirements of coal units.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[107] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built, including 15,726 MW that should already be in service based on the original queue date, but that is not yet even under construction. These projects may also create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

Key Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects. The backbone projects are intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm – Doubs, Jacks Mountain, and Susquehanna – Roseland.

Regional Transmission Expansion Plan (RTEP)

- On October 3, 2013, the PJM Board of Managers authorized $1.2 billion in transmission upgrades and improvements that were identified as part of PJM's continued regional planning process.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[108] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

Section 12 Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition

106 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones. SWMAAC consists of the BGE and Pepco Control Zones. See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

107 OATT Parts IV & VI.

108 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

among transmission developers to build transmission projects.[109] The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no evaluation of whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be a goal of PJM market design.

The PJM queue evaluation process needs to be enhanced to ensure that barriers to competition are not created. There appears to be a substantial amount of non-viable MW in the queues, which increase interconnection costs for projects behind them. The MMU recommends the establishment of a PJM review process to ensure that projects are removed from the queue, if they are not viable.

Overview: Section 13, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can also sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period through September 30, 2013, total participant FTR sell offers were 2,334,947 MW, up from 2,217,995 MW for the same period during the 2012 to 2013 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 5.9 percent from 9,223,203 MW for the first four months of the prior planning period, to 9,765,083 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 75.6 percent of prevailing flow and 85.7 percent of counter flow FTRs for January through September of 2013. Financial entities owned 62.2 percent of all prevailing and counter flow FTRs, including 53.4 percent of all prevailing flow FTRs and 79.4 percent of all counter flow FTRs during the January through September 2013 period.

Market Behavior

- **FTR Forfeitures.** Total forfeitures of FTR profits resulting from the FTR forfeiture rule for the 2013 to 2014 planning period, through August 2013, were $440,526 for Increment Offers and Decrement Bids.
- **Credit Issues.** Eight participants defaulted in 2013, through August, from twelve default events. The average of these defaults was $320,125 with nine based on inadequate collateral and three based on nonpayment. The average collateral default was $377,579 and the average nonpayment default was $147,761. The majority of these defaults were promptly cured, with one partial cure. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** For the 2013 to 2014 planning period, through September 2013, the Monthly Balance of Planning Period FTR Auctions cleared 1,308,752 MW (13.4 percent) of FTR buy bids and 443,885 MW (19.0 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period, through September 2013, was $0.07, down from $0.11 per MW for the same time period in the 2012 to 2013 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $7.3 million in net revenue for all FTRs for the first four months of the 2013 to 2014 planning period, down from $11.9 million for the same time period in the 2012 to 2013 planning period.
- **Revenue Adequacy.** FTRs were paid at 67.8 percent of the target allocation for the entire 2012 to 2013 planning period. FTRs were paid at 77.3 percent

109 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

of the target allocation level for the first four months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $287.4 million of FTR revenues during the 2013 to 2014 planning period through September 30, 2013 and $614.0 million during the 2012 to 2013 planning period.

For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion Zone and Northern Illinois Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were Vienna and Western Hub.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $138.8 million in profits for physical entities, of which $134.0 million was from self-scheduled FTRs, and $132.1 million for financial entities. Not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in March 2013.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the Annual ARR Allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. For the 2013 to 2014 planning period, through September 2013, PJM allocated a total of 11,586.4 MW of residual ARRs with a total target allocation of $3.3 million.

- **ARR Reassignment for Retail Load Switching.** There were 25,157 MW of ARRs associated with approximately $125,800 of revenue that were reassigned in the first four months of the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2013 to 2014 planning period, the ARR target allocations were $503.4 million while PJM collected $559.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2012 to 2013 planning period, the ARR target allocations were $565.4 million while PJM collected $614.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate for that period.

- **ARRs and FTRs as an Offset to Congestion.** The effectiveness of ARRs as an offset to congestion can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2013 to 2014 planning period through September 30, 2013, the total revenues received by ARR holders, including self-scheduled FTRs, offset 85.5 percent of the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2012 to 2013 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 92.6 percent of the total congestion costs within PJM and for the 2011 to 2012 planning period 88.9 percent.

Section 13 Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.

- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.

Section 13 Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. ARRs now serve that function. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. In the PJM model, FTRs are a financial product that PJM makes available when excess transmission capability permits.

Revenue adequacy has received a lot of attention in the PJM FTR market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and real-time markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2013 the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. The MMU recommends that the calculation of the monthly FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling in the FTR auction model which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real time markets, including reactive interfaces, which directly results in differences in congestion between day ahead and real time markets; differences in day-ahead and real time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load, which directly results in differences in congestion between day ahead and real time markets; the overallocation of ARRs which directly results in underfunding; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to FTR underfunding; and the continued sale of FTR capability on persistently underfunded pathways. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion.

Recommendations

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[1] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[2] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[3] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Summary of New Recommendations

Table 2-1 includes a brief description and a priority ranking of the MMU's new recommendations for this quarterly report.

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects.

Table 2-1 Prioritized summary of new recommendations: July through September 2013

Priority	Section	Description
Medium	4 - Operating Reserves	Reflect impact of all physical constraints in market prices.
High	5 - Capacity	Increase the Capacity Resource Deficiency Charge.
High	5 - Capacity	Require PJM to sell excess capacity, if necessary, in Incremental Auctions at the BRA clearing price.
High	5 - Capacity	Eliminate requirement for First and Second Incremental Auctions.
High	5 - Capacity	Define Market Seller Offer Cap for First and Second Incremental Auctions, if held, as higher of 1.0 times the Base Residual Auction clearing price or ACR.
High	5 - Capacity	Enforce the rules governing the requirement to be a physical resource for all resource types.
Low	6 - Demand Response	Adopt the ISO-NE demand response metering requirements.
Low	6 - Demand Response	The MMU recommends that demand resources be required to provide their nodal location.
Low	9 - Interchange Transactions	Align interface pricing definitions between PJM and MISO.
Medium	9 - Interchange Transactions	Eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.
Low	9 - Interchange Transactions	Eliminate the NIPSCO and Southeast interface pricing points.
High	10 - Ancillary Services	Eliminate rule paying for Tier 1 MW at Tier 2 clearing price when the non-synchronized reserve price is above $0.
High	13 - FTRs and ARRs	Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"6 the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets. In this *2013 Quarterly State of the Market Report for PJM: January through September*, the MMU makes the following new recommendations.

From Section 4, "Operating Reserves":

The MMU recommends that the impact of physical constraints of all types be reflected in market prices to the maximum extent possible, reducing the necessity for out of market operating reserve payments and improving the efficiency of market prices. The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

From Section 5, "Capacity":

The MMU's review and analysis of replacement capacity activity is the issue source for the problem statement/issue charge which is currently being discussed in the PJM stakeholder process.[7, 8] The MMU proposed a solution package at the Capacity Senior Task Force (CSTF) which includes the following:

- The MMU recommends that PJM increase the Capacity Resource Deficiency Charge, which is a penalty charge.
- The MMU recommends that if PJM releases capacity in Incremental Auctions, PJM should offer the capacity for sale at the BRA clearing price rather than at zero, which is the current practice, in order to avoid suppressing the price below the competitive level.
- The MMU recommends that PJM eliminate the requirement for First and Second Incremental Auctions and hold such auctions only if required based on increases in the Reliability Requirement above defined thresholds.
- The MMU recommends that PJM define the Market Seller Offer Cap for First and Second Incremental Auctions, if held, as the higher of the Base Residual Auction clearing price or the unit specific ACR in order to avoid suppressing the price below the competitive level.
- The MMU recommends that the rules governing the requirement that capacity resources be physical resources be enforced for all resource types.[9]

From Section 6, "Demand Response":

- The MMU recommends that PJM adopt the ISO-NE metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to DR resources are based on actual metered data. The provision of actual meter load data is critical in order to measure and verify actual demand resource behavior.
- The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation. More locational deployment of Load Management resources would improve efficiency.

From Section 9, "Interchange Transactions":

- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. PJM and MISO use network models to determine interface prices and to attempt to ensure that the prices are consistent with

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
7 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf> (December 18, 2012).
8 The Replacement Capacity Issue Charge and Problem Statement were presented at the March 6, 2013 MIC meeting. See "Item 04B – Replacement Capacity Issue Charge," < http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-04b-replacement-capacity-issue-charge.ashx>.
9 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_Replacemen_Activity_2_20130913.pdf> (September 13, 2013).

the underlying electrical flows. PJM uses the LMP at nine buses within MISO to calculate the PJM/MISO Interface price, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price. Differences in interface price calculations between PJM and MISO limit the ability for price convergence. The use of a common interface price definition including similarly located buses and comparable weights for those buses would help to converge the prices by eliminating artificial limits to that convergence.

- The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority. The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. During the first nine months of 2013, 5,000 GWh of the 5,023 GWh of net scheduled transactions between PJM and IESO wheeled through MISO.
- The MMU recommends that PJM no longer accept long term positions of any kind at the NIPSCO and Southeast interface pricing points and to eliminate these interface pricing points from the Day-Ahead and Real-Time Energy Markets. These two interface pricing points are currently eligible for day-ahead transaction scheduling only because they were replaced as interfaces in the Real-time Energy Market and are no longer actual interface pricing points in PJM markets. The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. After the MISO integration, all real-time transactions sourcing or sinking in NIPSCO receive the MISO interface pricing point in the Real-time Energy Market. PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.

From Section 10, “Ancillary Services”:

- The MMU recommends that the rule requiring the payment of Tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. Tier 1 synchronized reserve has always been available to respond optionally to spinning events, and Tier 1 synchronized reserve that responds to a spinning event is compensated at the average of the 5-minute energy LMPs plus $50/MWh. This rule significantly increases the cost of Tier 1 synchronized reserves with no operational or economic reason to do so. PJM is not actually reserving any Tier 1, but simply paying substantially more for the same product without any additional performance requirements. Although Tier 1 synchronized reserve adds no cost in most hours, the change to the shortage pricing rule resulted in extremely large charges for Tier 1 reserves for a small number of hours. The rule change requires the payment of all Tier 1 reserves the full Tier 2 synchronized reserve clearing price in the hours when the non synchronized reserve market has a price greater than zero. More credits were paid to Tier 1 reserves during the 206 hours when the non-synchronized reserve price was above zero ($11.8M) than was paid to Tier 2 synchronized reserve ($10.8M) (Table 10-18) for the entire first three quarters of 2013. This is a windfall payment to Tier 1 reserves without any logical rationale.

From Section 13, “FTRs and ARRs”:

- The MMU recommends that the FTR forfeiture rule be applied to UTCs in the same way it is applied to INCs and DECs. Currently there is no FTR forfeiture rule implemented for Up-to-Congestion Transactions (UTCs). A proposed tariff change that would apply the FTR forfeiture rule to UTCs is pending at FERC. The FTR forfeiture rule should be applied to UTCs in the same way it is applied to INCs and DECs. The goal of the rule is to prevent the use of virtual bids (generally unprofitable virtual bids) to increase Day-Ahead congestion on an FTR path in order to increase the value of the FTRs. The proposed penalty should be the same as it is for the INC and DEC rule, the forfeiture of any profits from FTRs whose value is affected by a UTC with the same owner.

Energy Market

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first nine months of 2013, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2013.

Table 3-1 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1180 with a minimum of 871 and a maximum of 1610 in the first nine months of 2013.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive,

1 Analysis of 2013 market results requires comparison to prior years. In 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2012 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 OATT Attachment M.

applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3]

Overview

Market Structure

- **Supply.** Average offered supply increased by 2,646, or 1.5 percent, from 173,414 MW in the first nine months of 2012 to 176,060 MW in the first nine months of 2013.[4] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 731 MW of new capacity were added to PJM. This new supply was partially offset by the deactivation of 7 units (476.9 MW) since January 1, 2013.

- **Demand.** The PJM system peak load for the first nine months of 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for the first nine months of 2012, which was 154,344 MW in the HE 1700 on July 17, 2012.[5]

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping for Energy.** PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first nine months of 2013. PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.1 percent in the first nine months of 2012 to 0.2 percent in the first nine months of 2013. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.1 percent in the first nine months of 2012 to 0.5 percent in the first nine months of 2013.

- **Reliability and Offer Capping.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.5 percent in the first nine months of 2012 to 3.0 percent in the first nine months of 2013. In the Day-Ahead Energy Market, for units committed to provide energy for reliability reasons, offer-capped unit hours increased from 0.2 percent in the first nine months of 2012 to 3.8 percent in the first nine months of 2013.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 81 units eligible for FMU or AU status in at least one month during the first nine months of 2013, 24 units (29.6 percent) were FMUs or AUs for all nine months, and 16 units (19.8 percent) qualified in only one month of 2013.

- **Local Market Structure.** In the first nine months of 2013, 10 Control Zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

4 Calculated values shown in Section 2, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

5 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2012 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

Market Performance: Markup, Load, Generation and LMP

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer.

  In the first nine months of 2013, the unadjusted markup was negative, -$1.21 per MWh, primarily as a result of competitive behavior by coal units and the competitive removal of the 10 percent adder. The adjusted markup was positive, $0.27 per MWh or 0.7 percent of the PJM real-time, load-weighted average LMP.

  The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** PJM average real-time load in the first nine months of 2013 increased by 0.5 percent from the first nine months of 2012, from 88,687 MW to 89,123 MW. The PJM average real-time load in 2013 would have decreased by 0.2 percent from the first nine months of 2012, from 88,687 MW to 88,522 MW, if the EKPC Transmission Zone had not been included in this comparison for the months prior to its integration to PJM.[6]

  PJM average day-ahead load in the first nine months of 2013, including DECs and up-to congestion transactions, increased by 9.5 percent from the first nine months of 2012, from 132,494 MW to 145,139 MW. The PJM average day-ahead load, including DECs and up-to congestion transactions, would have increased 9.1 percent from the first nine months of 2012, from 132,494 MW to 144,501 MW, if the EKPC Transmission Zone had not been included. The day-ahead load growth was 1,800.0 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Generation.** PJM average real-time generation in the first nine months of 2013 increased by 0.1 percent from the first nine months of 2012, from 90,367 MW to 90,432 MW. The PJM average real-time generation in the first nine months of 2013 would have decreased by 0.5 percent from the first nine months of 2012, from 90,367 MW to 89,910 MW, if the EKPC Transmission Zone had not been included.

  PJM average day-ahead generation in the first nine months of 2013, including INCs and up-to congestion transactions, increased by 9.8 percent from the first nine months of 2012, from 135,213 MW to 148,489 MW. The PJM average day-ahead generation, including INCs and up-to congestion transactions, would have increased by 9.4 percent from the first nine months of 2012, from 135,213 MW to 147,895 MW, if the EKPC Transmission Zone had not been included. The day-ahead generation growth was 9,700.0 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Generation Fuel Mix.** During the first nine months of 2013, coal units provided 44.5 percent, nuclear units 34.5 percent and gas units 16.5 percent of total generation. Compared to the first nine months of 2012, generation from coal units increased 6.2 percent, generation from nuclear units increased 0.9 percent, and generation from gas units decreased 16.1 percent. This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first nine months of 2013, particularly in eastern zones, and lower or constant coal prices.

6 The EKPC zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect the changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion.

  PJM Real-Time Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 15.0 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.30 per MWh versus $32.45 per MWh. The load-weighted average LMP was 13.5 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.75 per MWh versus $35.02 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 16.6 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.50 per MWh versus $32.16 per MWh. The load-weighted average LMP was 15.1 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.49 per MWh versus $34.29 per MWh.[7]

- **Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. For the first nine months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 24.1 percent by spot market purchases and 65.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot market purchases increased by 0.9 percentage points and reliance on self-supply decreased by 2.3 percentage points. For the first nine months of 2013, 7.5 percent of day-ahead load was supplied by bilateral contracts, 23.4 percent by spot market purchases, and 69.1 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot market purchases increased by 1.1 percentage points, and reliance on self-supply decreased by 1.9 percentage points.

7 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

Scarcity

- **Scarcity Pricing Events in 2013.** PJM's market did not experience any reserve-based scarcity events in the first nine months of 2013.

Recommendations

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[8]

8 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 22 (February 28, 2013).

The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[9]

- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007 and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders are no longer required to serve the purpose for which they were created, and the adders now interfere with the efficient operation of PJM markets. This recommendation is currently scheduled to be evaluated through the PJM stakeholder process in the fourth quarter of 2013.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during Maximum Emergency Events.[10]

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first nine months of 2013, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Average real-time supply offered increased by 2,646 MW in the first nine months of 2013 compared to the first nine months of 2012, while peak load increased by 3,165 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first nine months of 2013 generally reflected supply-demand fundamentals.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[11] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and

9 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

10 PJM Tariff, 6A.1.3 Maximum Emergency p. 1645, 1699-1700.

11 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented new scarcity pricing rules in 2012. There are significant issues with the scarcity pricing true up mechanism in the new PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2013.

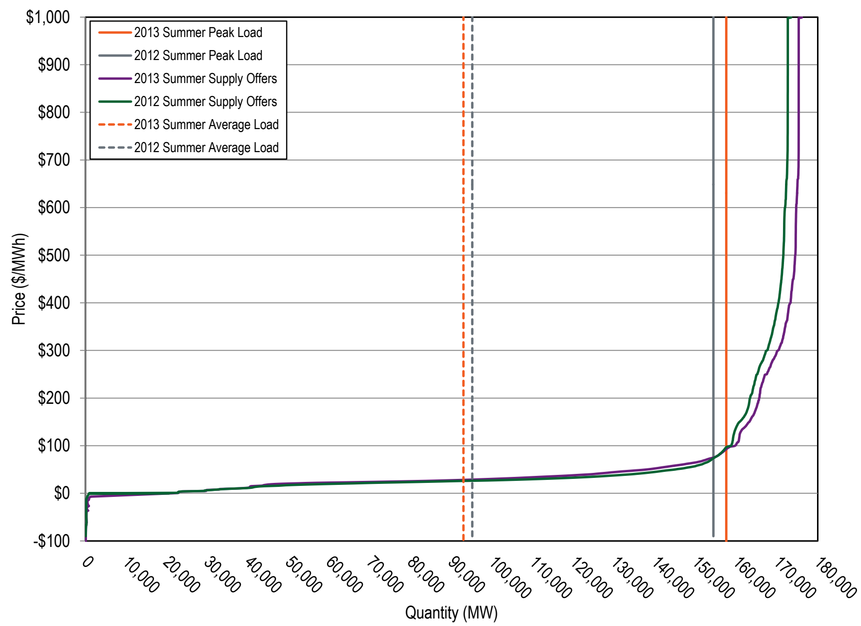
Market Structure

Supply

Average offered supply increased by 2,646 MW, or 1.5 percent, from 173,414 MW in the first nine months of 2012 to 176,060 MW in the first nine months of 2013.[12] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 731 MW of new capacity were added to PJM. This new supply was partially offset by the deactivation of 7 units (476.9 MW) since January 1, 2013.

Figure 3-1 shows the average PJM aggregate supply curves, peak load and average load for the summers of 2012 and 2013.

Figure 3-1 Average PJM aggregate supply curves: Summer of 2012 and 2013



Energy Production by Fuel Source

Compared to the first nine months of 2012, generation from coal units increased 6.2 percent and generation from natural gas units decreased 16.4 percent (Table 3-2). This represents a reversal of the recent trend of decreasing

12 Calculated values shown in Section 2, "Energy Market" are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first nine months of 2013, particularly in eastern zones, and lower or constant coal prices.

Table 3-2 PJM generation (By fuel source (GWh)): January through September 2012 and 2013[13]

	Jan-Sep 2012		Jan-Sep 2013		Change in
	GWh	Percent	GWh	Percent	Output
Coal	251,591.7	41.8%	267,112.3	44.5%	6.2%
Standard Coal	244,258.0	40.5%	259,835.6	43.2%	6.2%
Waste Coal	7,333.6	1.2%	7,276.7	1.2%	(0.0%)
Nuclear	205,503.9	34.1%	207,254.4	34.5%	0.9%
Gas	118,328.2	19.6%	99,264.9	16.5%	(16.1%)
Natural Gas	116,649.9	19.4%	97,550.2	16.2%	(16.4%)
Landfill Gas	1,678.0	0.3%	1,713.1	0.3%	2.1%
Biomass Gas	0.4	0.0%	1.7	0.0%	328.5%
Hydroelectric	9,768.1	1.6%	11,144.7	1.9%	14.1%
Wind	8,944.7	1.5%	10,379.3	1.7%	16.0%
Waste	3,894.1	0.6%	3,719.2	0.6%	(4.5%)
Solid Waste	3,156.5	0.5%	3,111.9	0.5%	(1.4%)
Miscellaneous	737.6	0.1%	607.2	0.1%	(17.7%)
Oil	4,337.1	0.7%	1,620.5	0.3%	(62.6%)
Heavy Oil	4,122.7	0.7%	1,440.3	0.2%	(65.1%)
Light Oil	201.3	0.0%	152.4	0.0%	(24.3%)
Diesel	8.2	0.0%	14.1	0.0%	71.3%
Kerosene	4.9	0.0%	13.6	0.0%	179.3%
Jet Oil	0.0	0.0%	0.1	0.0%	215.0%
Solar	192.7	0.0%	288.4	0.0%	49.7%
Battery	0.2	0.0%	0.4	0.0%	124.4%
Total	602,560.9	100.0%	600,784.1	100.0%	(0.3%)

13 Hydroelectric generation is total generation output and does not net out the MWh used at pumped storage facilities to pump water. Battery generation is total generation output and does not net out MWh absorbed.

Table 3-3 Monthly PJM Generation (By fuel source (GWh)): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	31,689.2	28,886.8	29,680.4	24,637.5	25,824.6	30,722.3	34,879.0	31,619.9	29,172.7	267,112.3
Standard Coal	30,814.3	28,102.4	28,670.2	24,060.8	24,962.6	29,884.0	33,916.0	30,862.6	28,562.7	259,835.6
Waste Coal	874.9	784.4	1,010.2	576.7	862.0	838.3	962.9	757.4	610.0	7,276.7
Nuclear	25,610.7	22,563.1	23,854.9	19,614.0	21,106.9	23,109.3	24,458.0	24,985.8	21,951.7	207,254.4
Gas	10,261.4	10,319.8	10,055.6	9,276.0	10,240.2	10,594.4	14,788.8	13,356.2	10,372.6	99,264.9
Natural Gas	10,072.4	10,143.6	9,859.7	9,096.1	10,047.2	10,404.5	14,593.7	13,158.1	10,174.8	97,550.2
Landfill Gas	189.0	176.2	195.9	179.9	193.0	189.8	195.1	198.1	196.2	1,713.1
Biomass Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	1.7
Hydroelectric	1,234.0	1,127.0	1,215.8	1,273.0	1,250.7	1,401.7	1,609.2	1,167.5	865.7	11,144.7
Wind	1,784.4	1,397.5	1,606.2	1,639.6	1,271.3	862.5	588.2	510.4	719.2	10,379.3
Waste	414.4	385.2	391.5	358.2	421.3	428.7	447.1	465.4	407.4	3,719.2
Solid Waste	324.8	301.5	325.2	323.9	349.9	368.6	385.3	382.3	350.4	3,111.9
Miscellaneous	89.6	83.7	66.2	34.3	71.4	60.2	61.8	83.0	57.0	607.2
Oil	62.5	23.8	50.3	79.1	220.3	190.7	629.8	154.8	209.2	1,620.5
Heavy Oil	55.8	21.9	27.9	66.8	206.1	179.4	575.0	139.9	167.6	1,440.3
Light Oil	4.2	1.5	17.7	11.7	13.2	10.7	43.6	13.0	36.7	152.4
Diesel	0.6	0.1	0.0	0.5	1.1	0.4	8.2	0.2	3.0	14.1
Kerosene	1.9	0.3	4.7	0.1	0.0	0.2	3.0	1.7	1.8	13.6
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Solar	15.6	17.6	26.7	38.1	39.6	38.4	37.9	35.6	39.0	288.4
Battery	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.4
Total	71,072.0	64,720.7	66,881.4	56,915.4	60,374.9	67,348.2	77,438.0	72,295.8	63,737.6	600,784.1

Generator Offers

Generator offers are categorized as dispatchable and self scheduled.[14,15] Table 3-4 shows the average hourly distribution of MW offers by dispatchable units by offer prices for the first nine months of 2013. Table 3-5 shows the average hourly distribution of MW offers by self-scheduled units by offer prices for the first nine months of 2013. Of the dispatchable MW offered by combustion turbines (CT), 23.0 percent were dispatchable at an offered range of $600 to $800. Only wind and solar units have negative offer prices.

Table 3-4 Distribution of MW for dispatchable unit offer prices: January through September, 2013

	Dispatchable (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	64.5%	11.7%	2.7%	4.1%	0.8%	83.8%
CT	0.0%	49.1%	15.8%	9.4%	23.0%	2.3%	99.6%
Diesel	0.0%	8.0%	50.1%	6.3%	1.2%	0.8%	66.4%
Hydro	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.2%
Nuclear	0.0%	10.2%	0.0%	0.0%	0.0%	0.0%	10.2%
Pumped Storage	0.0%	51.6%	0.0%	0.0%	0.0%	0.0%	51.6%
Solar	0.0%	58.3%	0.0%	0.0%	0.0%	0.0%	58.3%
Steam	0.0%	49.4%	10.3%	0.6%	0.1%	0.0%	60.5%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	27.4%	28.2%	0.0%	0.0%	0.0%	0.0%	55.6%
All Dispatchable Offers	0.8%	43.1%	9.2%	2.5%	5.1%	0.6%	61.1%

14 Each range in the tables is greater than or equal to the lower value and less than the higher value.
15 The unit type battery is not included in these tables because batteries do not make energy offers.

Table 3-5 Distribution of MW for self-scheduled unit offer prices: January through September, 2013

	Self Scheduled (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	14.2%	1.9%	0.0%	0.0%	0.0%	16.2%
CT	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.4%
Diesel	0.0%	32.6%	0.2%	0.0%	0.0%	0.8%	33.6%
Hydro	0.0%	98.7%	0.0%	0.0%	0.0%	1.0%	99.8%
Nuclear	0.0%	89.8%	0.0%	0.0%	0.0%	0.0%	89.8%
Pumped Storage	0.0%	48.4%	0.0%	0.0%	0.0%	0.0%	48.4%
Solar	0.6%	41.1%	0.0%	0.0%	0.0%	0.0%	41.7%
Steam	0.0%	26.6%	12.6%	0.0%	0.1%	0.1%	39.5%
Transaction	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	16.3%	28.2%	0.0%	0.0%	0.0%	0.0%	44.4%
All Self-Scheduled Offers	0.5%	32.6%	5.6%	0.0%	0.0%	0.1%	38.9%

Demand

The PJM system peak load for the first nine months 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for the first nine months of 2012, which was 154,344 MW in the HE 1700 on July 17, 2012. The EKPC Transmission Zone accounted for 2,175 MW in the peak hour of the first nine months of 2013. The peak load excluding the EKPC transmission zone was 155,333 MW, also occurring on July 18, 2013, HE 1700, an increase of 990 MW, or 0.6 percent.

Table 3-6 shows the coincident peak loads for the first nine months of 1999 through 2013.

Table 3-6 Actual PJM footprint peak loads: January through September, 1999 to 2013[16]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, July 06	14	51,689	NA	NA
2000	Wed, August 09	17	49,469	(2,220)	(4.3%)
2001	Thu, August 09	15	54,015	4,546	9.2%
2002	Wed, August 14	16	63,762	9,747	18.0%
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Tue, August 03	17	77,887	16,387	26.6%
2005	Tue, July 26	16	133,761	55,875	71.7%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013 (with EKPC)	Thu, July 18	17	157,508	3,165	2.1%
2013 (without EKPC)	Thu, July 18	17	155,333	990	0.6%

16 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load.

Figure 3-2 shows the peak loads for the first nine months of 1999 through 2013.

Figure 3-2 PJM footprint calendar year peak loads: January through September of 1999 to 2013

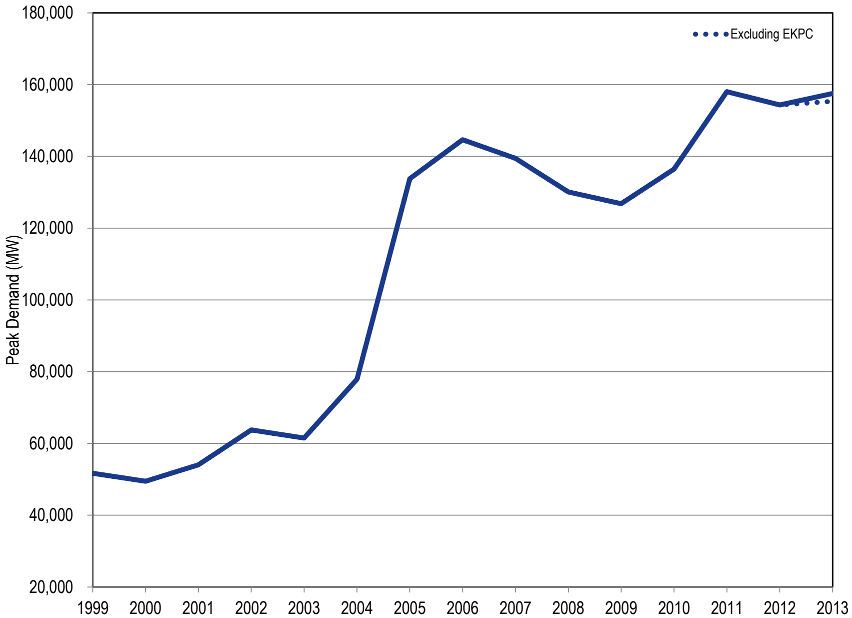
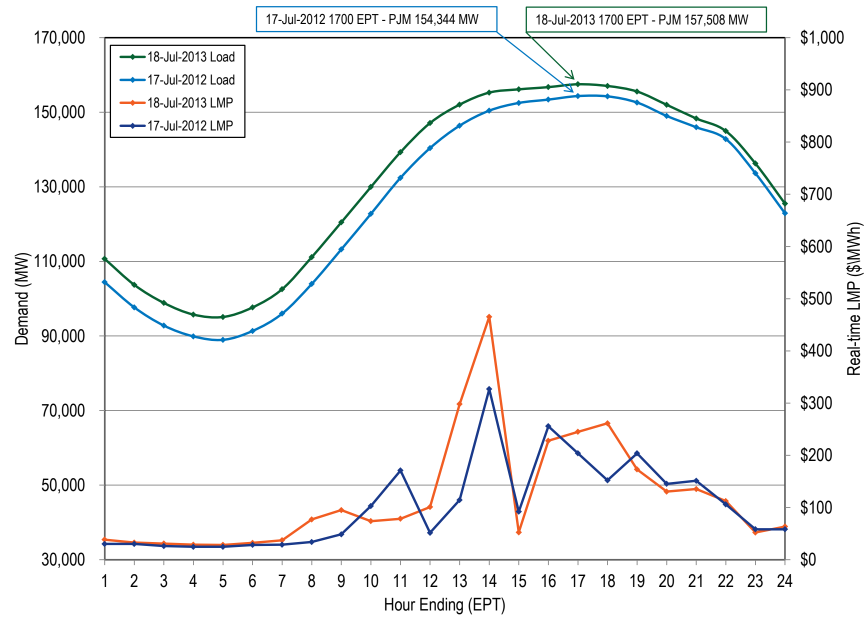


Figure 3-3 compares the peak load days in the first nine months of 2012 and 2013. In every hour on July 18, 2013, the average hourly real-time load was higher than the average hourly real-time load on July 17, 2012. The average hourly real-time LMP peaked at $465.18 on July 18, 2013 and peaked at $326.72 on July 17, 2012.

Figure 3-3 PJM peak-load comparison: Thursday, July 18, 2013, and Tuesday, July 17, 2012



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first nine months of 2013 indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[17] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in these areas during the first nine months of 2013.

17 A unit is classified as base load if it runs for more than 50 percent of the total hours, as intermediate if it runs for less than 50 percent but greater than 10 percent of the total hours, and as peak if it runs for less than 10 percent of the total hours.

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 3-7).

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[18]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2013 was moderately concentrated (Table 3-7).

Table 3-7 PJM hourly Energy Market HHI: January through September, 2012 and 2013[19]

	Hourly Market HHI (Jan - Sep, 2012)	Hourly Market HHI (Jan - Sep, 2013)
Average	1234	1180
Minimum	927	871
Maximum	1657	1610
Highest market share (One hour)	32%	31%
Average of the highest hourly market share	23%	22%
# Hours	6,575	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-8 includes 2013 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 3-8 PJM hourly Energy Market HHI (By supply segment): January through September, 2012 and 2013

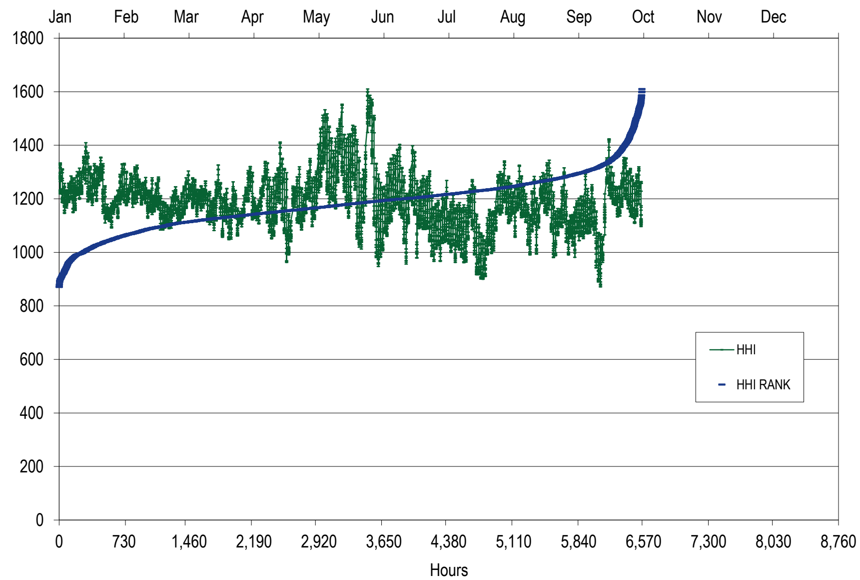
	Jan - Sep, 2012			Jan - Sep, 2013		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1082	1268	1691	901	1095	1484
Intermediate	849	1919	8301	835	2266	8429
Peak	619	5699	10000	694	6329	10000

18 Order No. 592, *"Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement,"* 77 FERC ¶ 61,263, pp. 64-70 (1996)

19 This analysis includes all hours in the first nine months of 2013, regardless of congestion.

Figure 3-4 presents the 2013 hourly HHI values in chronological order and an HHI duration curve.

Figure 3-4 PJM hourly Energy Market HHI: January through September, 2013



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service. There are no explicit rules governing market structure or the exercise of market power in the aggregate Energy Market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

Levels of offer capping have historically been low in PJM, as shown in Table 3-9. The offer capping percentages shown in Table 3-9 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market, excluding offer capping for reliability reasons.

Table 3-9 Offer-capping statistics – Energy only: January through September, 2009 to 2013

	Real Time		Day Ahead	
(Jan - Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.5%	0.1%	0.1%	0.0%
2010	1.2%	0.3%	0.3%	0.1%
2011	0.7%	0.3%	0.0%	0.0%
2012	1.1%	0.6%	0.1%	0.1%
2013	0.5%	0.2%	0.2%	0.1%

Table 3-10 shows the offer capping percentages including units committed to provide constraint relief as well as units committed to provide reactive support. The units that are committed and offer capped for reactive support have been steadily increasing since 2011. Before 2011, the units that ran to provided reactive support were generally economic in the energy market. Since 2011, the percentage of hours when these units were out of the money (and are therefore committed on their cost schedule to provide reactive) has steadily increased. Black start service is not considered a transmission constraint and is therefore not included in the statistics presented in this section.

Table 3-10 Offer-capping statistics for energy and reactive support: January through September, 2009 to 2013

	Real Time		Day Ahead	
(Jan - Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.5%	0.1%	0.1%	0.0%
2010	1.2%	0.3%	0.3%	0.1%
2011	0.8%	0.3%	0.0%	0.0%
2012	1.1%	0.7%	0.2%	0.1%
2013	2.2%	1.9%	2.4%	1.8%

Table 3-11 presents data on the frequency with which units were offer capped in the first nine months of 2012 and 2013 for failing the TPS test to provide energy for constraint relief in the real time energy market.

Table 3-11 Real-time offer-capped unit statistics: January through September, 2012 and 2013[20]

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Sep)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2013	0	0	0	0	0	0
	2012	0	0	1	0	1	1
80% and < 90%	2013	0	0	0	1	1	1
	2012	0	0	1	0	1	4
75% and < 80%	2013	0	0	0	1	1	3
	2012	0	0	1	0	0	0
70% and < 75%	2013	0	0	0	0	0	3
	2012	0	0	0	0	1	3
60% and < 70%	2013	0	0	0	0	0	6
	2012	0	0	0	1	1	8
50% and < 60%	2013	0	0	0	0	0	9
	2012	1	0	1	0	1	6
25% and < 50%	2013	0	0	6	0	5	50
	2012	2	0	1	2	2	43
10% and < 25%	2013	2	0	0	0	3	45
	2012	0	0	0	1	3	57

Table 3-11 shows that a small number of units are offer capped for 90 percent or more of their run hours in the first nine months of 2013.

Units that are offer capped for greater than, or equal to, 60 percent of their run hours are designated as frequently mitigated units (FMUs). An FMU or units that are associated with the FMU (AUs) are entitled to include adders in their cost-based offers that are a form of local scarcity pricing.

Local Market Structure

In the first nine months of 2013, the AEP, ATSI, BGE, ComEd, Dominion, DPL, PECO, Pepco, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 75 or more hours. Actual competitive conditions in the Real-Time Energy Market associated with each of these frequently binding constraints were analyzed using the three pivotal supplier results for the first nine months of 2013.[21] The AECO, AP, DAY, DEOK, DLCO, JCPL, Met-Ed, PENELEC and RECO Control Zones were not affected by constraints binding for 75 or more hours.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2013, through September 30, 2013. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Table 3-12 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints.

20 This table was modified from the previous State of the Market report to include only units that are offer capped for failing the TPS test in the real time energy market.

21 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

Table 3-12 Three pivotal supplier test details for interface constraints: January through September, 2013

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	270	312	13	2	11
	Off Peak	206	288	12	3	9
AEP - DOM	Peak	156	89	6	0	6
	Off Peak	0	0	0	0	0
AP South	Peak	307	470	10	1	9
	Off Peak	336	507	10	1	9
ATSI	Peak	321	717	15	12	3
	Off Peak	0	0	0	0	0
Bedington - Black Oak	Peak	156	139	11	2	10
	Off Peak	152	106	10	0	10
Cleveland	Peak	100	112	2	0	2
	Off Peak	0	0	0	0	0
Eastern	Peak	463	619	16	2	14
	Off Peak	0	0	0	0	0
PL North	Peak	0	0	0	0	0
	Off Peak	151	321	2	0	2
Western	Peak	463	754	16	5	11
	Off Peak	1,438	2,068	21	8	14

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 3-13 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

Table 3-13 Summary of three pivotal supplier tests applied for interface constraints: January through September, 2013

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	684	53	8%	17	2%	32%
	Off Peak	617	51	8%	15	2%	29%
AEP - DOM	Peak	38	0	0%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
AP South	Peak	4,826	213	4%	46	1%	22%
	Off Peak	3,319	101	3%	23	1%	23%
ATSI	Peak	144	4	3%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
Bedington - Black Oak	Peak	11	0	0%	0	0%	0%
	Off Peak	145	5	3%	4	3%	80%
Cleveland	Peak	108	6	6%	3	3%	50%
	Off Peak	0	0	0%	0	0%	0%
Eastern	Peak	8	0	0%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
PL North	Peak	0	0	0%	0	0%	0%
	Off Peak	212	0	0%	0	0%	0%
Western	Peak	316	14	4%	7	2%	50%
	Off Peak	253	7	3%	5	2%	71%

Ownership of Marginal Resources

Table 3-14 shows the contribution to PJM real-time, nine month, load-weighted LMP by individual marginal resource owner.[22] The contribution of each marginal resource to price at each load bus is calculated for the first nine months of 2013, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first nine months of 2013, the offers of one company contributed 20.8 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 54.2 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during the first nine months of 2012, the offers of one company contributed 21.4 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 54.0 percent of the real-time, load-weighted, average PJM system LMP.

Table 3-14 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through September 2012 and 2013

2012 (Jan - Sep)		2013 (Jan - Sep)	
Company	Percent of Price	Company	Percent of Price
1	21.4%	1	20.8%
2	13.1%	2	13.6%
3	11.2%	3	10.4%
4	8.3%	4	9.5%
5	8.0%	5	7.3%
6	6.0%	6	5.2%
7	5.6%	7	3.9%
8	5.6%	8	3.8%
9	3.9%	9	3.4%
Other (52 companies)	16.9%	Other (58 companies)	22.1%

Table 3-15 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[23] The contribution of each marginal resource to price at each load bus is calculated for the first nine months of 2013, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

22 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."
23 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-15 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through September, 2012 and 2013

2012 (Jan - Sep)		2013 (Jan - Sep)	
Company	Percent of Price	Company	Percent of Price
1	15.2%	1	21.3%
2	6.6%	2	8.7%
3	6.4%	3	8.2%
4	6.2%	4	7.7%
5	6.0%	5	7.1%
6	4.8%	6	4.2%
7	4.8%	7	3.4%
8	4.1%	8	3.2%
9	3.8%	9	3.2%
Other (137 companies)	42.1%	Other (141 companies)	32.9%

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources, particularly in the Day-Ahead Market. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Market that can set price via their offers and bids.

Table 3-16 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2013, coal units were 58.54 percent and natural gas units were 32.51 percent of the total marginal resources. In the first nine months of 2012, coal units were 58.11 percent and natural gas units were 30.82 percent of the total marginal resources.[24]

24 The percentages of marginal fuel reported in the *2011 State of the Market Report for PJM*, were based on both Locational Pricing Algorithm (LPA) and dispatch (SCED) marginal resources. Starting from *2012 State of the Market Report for PJM*, marginal fuel percentages are based only on resources that were marginal in dispatch (SCED). See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-16 Type of fuel used (By real-time marginal units): January through September, 2012 and 2013

Fuel Type	2012 (Jan - Sep)	2013 (Jan - Sep)
Coal	58.11%	58.54%
Demand Response	0.00%	0.03%
Gas	30.82%	32.51%
Municipal Waste	0.14%	0.08%
Oil	6.04%	3.86%
Other	0.58%	0.21%
Uranium	0.01%	0.02%
Wind	4.30%	4.75%

Table 3-17 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2013, Up-to Congestion transactions were 96.2 percent of the total marginal resources. In comparison, Up-to Congestion transactions were 86.7 percent of the total marginal resources in the first nine months of 2012.

Table 3-17 Day-ahead marginal resources by type/fuel: January through September, 2012 and 2013

Type/Fuel	2012 (Jan - Sep)	2013 (Jan - Sep)
Up-to Congestion Transaction	86.7%	96.2%
DEC	5.2%	1.2%
INC	4.4%	1.0%
Coal	2.5%	1.0%
Gas	1.1%	0.4%
Dispatchable Transaction	0.1%	0.1%
Price Sensitive Demand	0.1%	0.0%
Wind	0.0%	0.0%
Oil	0.0%	0.0%
Municipal Waste	0.0%	0.0%
Diesel	0.0%	0.0%
Total	100.0%	100.0%

Market Conduct: Markup

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[25] The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Mark Up Conduct

Table 3-18 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. For convenience, the marginal units are grouped into one of seven categories based on their respective offer prices. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. The data shows that despite the fact that markup had a negligible impact on LMP in the first nine months of 2013, some marginal units do have substantial markups.

Table 3-18 Average, real-time marginal unit markup index (By price category): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.43)	31.0%	0.02	($3.29)	17.4%
$25 to $50	(0.05)	($2.81)	48.9%	(0.02)	($1.84)	62.2%
$50 to $75	0.05	$1.12	4.4%	(0.02)	($5.86)	8.7%
$75 to $100	0.33	$28.81	0.6%	0.00	($5.86)	1.5%
$100 to $125	0.21	$21.28	0.6%	0.11	$10.77	0.7%
$125 to $150	0.17	$23.44	0.3%	0.08	$11.14	0.9%
>= $150	0.04	$9.59	5.5%	0.04	$8.63	4.5%

25 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

Day-Ahead Mark Up Conduct

Table 3-19 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 3-19 Average marginal unit markup index (By offer price category): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.01)	32.2%	(0.06)	($1.76)	18.9%
$25 to $50	(0.05)	($2.56)	64.2%	(0.04)	($2.41)	75.4%
$50 to $75	0.09	$4.13	3.1%	0.00	($2.72)	4.6%
$75 to $100	0.45	$36.25	0.2%	0.08	$7.07	0.4%
$100 to $125	0.00	$0.00	0.0%	0.00	$0.00	0.1%
$125 to $150	(0.06)	($8.33)	0.1%	0.00	$0.00	0.0%
>= $150	0.03	$4.84	0.2%	0.75	$118.80	0.0%

Market Performance

Markup

The markup index, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[26]

26 This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP.

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-20 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 3-20 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-18.

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach, markup is simply the difference between the active offer of the marginal unit and the cost offer. In the second approach, the 10 percent markup is removed from the cost offers of coal units because coal units do not face the same cost uncertainty as gas-fired CTs. The adjusted markup is calculated as the difference between the active offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the active offer and the cost offer including the 10 percent adder in the cost offer.

Table 3-20 shows mark-up component of the load weighted LMP by primary fuel and unit-type using unadjusted and adjusted offers.

Markup Component of Real-Time System Price

Table 3-21 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-22 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first nine months of 2013, when using unadjusted cost offers, - $ 1.21 per MWh of the PJM real-time load weighted average LMP was attributable to markup. Using adjusted cost-offers, $ 0.27 per MWh of the PJM real-time load weighted average LMP was attributable to markup. In the first nine months of 2013, the real time load-weighted average LMP for the month of July had the highest markup component.

Table 3-20 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September, 2012 and 2013[27]

		2012 (Jan Sep)		2013 (Jan - Sep)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.64)	$0.21	($0.42)	$1.06
Demand Response	Demand Response	$0.00	$0.00	$0.00	$0.00
Gas	CC	$0.55	$0.55	($0.28)	($0.28)
Gas	CT	($0.06)	($0.06)	$0.03	$0.03
Gas	Diesel	$0.03	$0.03	$0.02	$0.02
Gas	Steam	($0.04)	($0.04)	$0.00	$0.00
Municipal Waste	Diesel	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Steam	$0.03	$0.03	($0.00)	($0.00)
Oil	CT	$0.01	$0.01	$0.00	$0.00
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.09)	($0.09)	($0.54)	($0.54)
Other	Solar	$0.00	$0.00	$0.00	$0.00
Other	Steam	($0.00)	($0.00)	($0.02)	($0.02)
Uranium	Steam	$0.00	$0.00	($0.00)	($0.00)
Wind		($0.01)	($0.01)	$0.00	$0.00
Total		($1.23)	$0.62	($1.21)	$0.27

27 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and municipal waste.

Table 3-21 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.28)	($3.58)	($2.98)	($4.04)	($4.39)	($3.70)
Feb	($2.07)	($2.92)	($1.26)	($2.54)	($3.77)	($1.34)
Mar	($2.30)	($2.51)	($2.10)	($1.20)	($1.89)	($0.48)
Apr	($2.71)	($3.60)	($1.86)	($2.15)	($3.23)	($1.22)
May	($1.10)	($3.34)	$0.93	($0.87)	($2.03)	$0.10
Jun	($2.67)	($3.24)	($2.17)	($1.17)	($1.12)	($1.21)
Jul	$3.38	($2.36)	$8.82	$2.97	($1.43)	$6.85
Aug	($0.90)	($2.30)	$0.20	($1.58)	($1.73)	($1.45)
Sep	($0.70)	($1.89)	$0.60	($0.93)	($2.34)	$0.46
Total	($1.23)	($2.84)	$0.28	($1.21)	($2.42)	($0.09)

Table 3-22 Monthly markup components of real-time load-weighted LMP (Adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($0.93)	($1.40)	($0.43)	($2.22)	($2.43)	($2.02)
Feb	($0.06)	($1.04)	$0.87	($0.75)	($1.87)	$0.33
Mar	($0.59)	($1.07)	($0.15)	$0.46	($0.13)	$1.08
Apr	($0.81)	($1.79)	$0.11	($0.91)	($1.61)	($0.31)
May	$0.64	($1.71)	$2.78	$0.43	($0.45)	$1.17
Jun	($1.14)	($1.92)	($0.45)	$0.21	$0.26	$0.16
Jul	$5.08	($0.47)	$10.34	$4.32	$0.09	$8.05
Aug	$1.07	($0.60)	$2.38	($0.30)	($0.36)	($0.25)
Sep	$1.01	($0.29)	$2.45	$0.56	($0.58)	$1.68
Total	$0.62	($1.11)	$2.25	$0.27	($0.76)	$1.24

Markup Component of Real-Time Zonal Prices

The average real-time price component of unit markup using unadjusted offers is shown for each zone for the first nine months of 2013 in Table 3-23 and for adjusted offers in Table 3-25. The smallest zonal all hours average markup component using unadjusted offers for the first nine months of 2013 was in the PPL Control Zone, -$1.67 per MWh, while the highest all hours average zonal markup component for the first nine months of 2013 was in the JCPL Control Zone, $1.42 per MWh. The smallest zonal on peak average markup was in the PPL Control Zone, -$0.97 per MWh, while the highest zonal on peak average markup was in the JCPL Control Zone, $4.79 per MWh.

Table 3-23 Average real-time zonal markup component (Unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($1.09)	($2.67)	$0.42	($0.82)	($2.18)	$0.47
AEP	($1.48)	($2.86)	($0.14)	($1.48)	($2.53)	($0.48)
APS	($1.29)	($2.84)	$0.19	($1.55)	($2.65)	($0.52)
ATSI	($1.44)	($3.04)	$0.04	($1.42)	($2.46)	($0.46)
BGE	($0.88)	($2.33)	$0.50	($1.37)	($2.39)	($0.42)
ComEd	($1.28)	($3.07)	$0.37	($1.25)	($2.40)	($0.21)
DAY	($1.54)	($3.03)	($0.17)	($1.47)	($2.54)	($0.51)
DEOK	($1.51)	($2.92)	($0.18)	($1.41)	($2.48)	($0.42)
DLCO	($1.23)	($2.87)	$0.30	($1.50)	($2.41)	($0.66)
DPL	($1.52)	($3.45)	$0.34	($1.41)	($2.28)	($0.58)
Dominion	($0.77)	($2.35)	$0.75	($1.22)	($2.48)	($0.02)
EKPC	$0.00	$0.00	$0.00	($0.43)	($1.91)	$0.96
JCPL	($0.82)	($2.87)	$1.03	$1.42	($2.36)	$4.79
Met-Ed	($1.40)	($3.05)	$0.12	($0.79)	($2.35)	$0.63
PECO	($1.23)	($2.84)	$0.27	($1.38)	($2.17)	($0.64)
PENELEC	($1.49)	($3.11)	$0.02	($1.38)	($2.58)	($0.27)
PPL	($1.47)	($3.06)	$0.01	($1.67)	($2.43)	($0.97)
PSEG	($1.09)	($2.94)	$0.61	($0.17)	($1.94)	$1.45
Pepco	($0.68)	($2.39)	$0.90	($1.31)	($2.46)	($0.26)
RECO	($0.92)	($3.02)	$0.86	$0.65	($1.68)	$2.63

Table 3-24 Average real-time zonal markup component (Adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.62	($1.12)	$2.29	$0.66	($0.53)	$1.80
AEP	$0.37	($1.13)	$1.82	$0.04	($0.85)	$0.88
APS	$0.65	($1.10)	$2.32	($0.04)	($0.96)	$0.83
ATSI	$0.39	($1.34)	$2.01	$0.12	($0.77)	$0.94
BGE	$1.27	($0.30)	$2.77	$0.16	($0.63)	$0.91
ComEd	$0.55	($1.32)	$2.27	$0.21	($0.82)	$1.14
DAY	$0.36	($1.28)	$1.87	$0.08	($0.84)	$0.91
DEOK	$0.31	($1.23)	$1.77	$0.08	($0.84)	$0.94
DLCO	$0.52	($1.26)	$2.19	($0.01)	($0.78)	$0.71
DPL	$0.26	($1.77)	$2.21	$0.06	($0.67)	$0.75
Dominion	$1.17	($0.52)	$2.78	$0.26	($0.79)	$1.25
EKPC	$0.00	$0.00	$0.00	$0.99	($0.35)	$2.25
JCPL	$0.93	($1.25)	$2.89	$2.74	($0.75)	$5.85
Met-Ed	$0.31	($1.49)	$1.96	$0.63	($0.76)	$1.89
PECO	$0.48	($1.24)	$2.09	$0.07	($0.59)	$0.69
PENELEC	$0.31	($1.43)	$1.94	$0.13	($0.91)	$1.09
PPL	$0.23	($1.50)	$1.84	($0.17)	($0.80)	$0.41
PSEG	$0.69	($1.31)	$2.51	$1.21	($0.37)	$2.66
Pepco	$1.33	($0.49)	$2.99	$0.17	($0.75)	$1.02
RECO	$0.92	($1.30)	$2.82	$2.01	($0.07)	$3.77

Markup by Real Time System Price Levels

Table 3-25 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-25 Average real-time markup component (By price category, unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.91)	28.0%	($0.41)	12.8%
$25 to $50	($1.81)	62.0%	($1.33)	72.8%
$50 to $75	$0.37	4.4%	($0.13)	7.4%
$75 to $100	$0.27	1.4%	$0.03	1.6%
$100 to $125	$0.15	0.7%	$0.09	0.7%
$125 to $150	$0.13	0.2%	$0.05	0.3%
>= $150	$0.57	0.6%	$0.48	0.5%

Table 3-26 Average real-time markup component (By price category, adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.62)	28.0%	($0.26)	12.8%
$25 to $50	($0.41)	62.0%	($0.09)	72.8%
$50 to $75	$0.46	4.4%	($0.06)	7.4%
$75 to $100	$0.30	1.4%	$0.05	1.6%
$100 to $125	$0.16	0.7%	$0.10	0.8%
$125 to $150	$0.14	0.2%	$0.06	0.3%
>= $150	$0.58	0.6%	$0.49	0.5%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the overall PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-27.

Table 3-27 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September, 2012 and 2013

		2012 (Jan - Sep)		2013 (Jan - Sep)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.68)	($0.70)	($0.51)	($0.19)
Gas	Steam	($0.20)	($0.15)	($0.46)	($0.46)
Oil	Steam	($0.08)	($0.08)	($0.00)	($0.00)
Municipal Waste	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Wind	Wind	($0.00)	($0.00)	$0.00	$0.00
Gas	CT	$0.09	$0.09	($0.02)	($0.02)
Total		($1.87)	($0.85)	($1.00)	($0.67)

Markup Component of Day-Ahead System Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced based offers or on cost based offers were included in the markup calculation.

Table 3-28 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-29 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers.

Table 3-28 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.76)	($2.22)	($3.28)	($3.77)	($3.99)	($3.54)
Feb	($3.01)	($3.61)	($2.38)	($2.53)	($1.43)	($3.67)
Mar	($2.30)	($1.99)	($2.63)	($1.84)	($0.18)	($3.45)
Apr	($2.67)	($2.36)	($2.98)	($0.11)	($0.01)	($0.22)
May	($1.52)	($1.11)	($1.97)	($0.10)	($0.04)	($0.17)
Jun	($1.93)	($1.09)	($2.88)	($0.06)	$0.03	($0.14)
Jul	$0.35	$2.60	($2.07)	($0.08)	($0.01)	($0.15)
Aug	($1.86)	($0.95)	($3.05)	($0.06)	($0.01)	($0.11)
Sep	($1.75)	($1.36)	($2.10)	($0.27)	($0.13)	($0.42)
Annual	($1.87)	($1.20)	($2.59)	($1.00)	($0.66)	($1.37)

Table 3-29 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.43)	($1.00)	($1.84)	($2.66)	($3.01)	($2.28)
Feb	($1.74)	($2.21)	($1.25)	($1.67)	($0.67)	($2.70)
Mar	($1.37)	($1.05)	($1.72)	($1.28)	$0.08	($2.61)
Apr	($1.49)	($1.18)	($1.81)	($0.03)	$0.04	($0.11)
May	($0.76)	($0.33)	($1.23)	($0.04)	($0.02)	($0.06)
Jun	($0.92)	($0.04)	($1.91)	($0.02)	$0.04	($0.07)
Jul	$1.24	$3.35	($1.03)	($0.03)	$0.02	($0.09)
Aug	($0.93)	($0.11)	($2.01)	($0.02)	$0.01	($0.05)
Sep	($0.82)	($0.44)	($1.17)	($0.17)	($0.08)	($0.26)
Annual	($0.85)	($0.20)	($1.54)	($0.67)	($0.42)	($0.95)

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-30. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-31.

Table 3-30 Day-ahead, average, zonal markup component (Unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.48)	($0.55)	($2.48)	($1.00)	($0.71)	($1.30)
AEP	($1.95)	($1.35)	($2.57)	($1.01)	($0.62)	($1.42)
AP	($1.83)	($1.38)	($2.31)	($1.10)	($0.71)	($1.50)
ATSI	($2.00)	($1.44)	($2.62)	($1.01)	($0.63)	($1.42)
BGE	($1.86)	($1.22)	($2.55)	($1.00)	($0.71)	($1.33)
ComEd	($1.83)	($1.29)	($2.41)	($0.91)	($0.55)	($1.31)
DAY	($1.89)	($1.25)	($2.60)	($1.02)	($0.62)	($1.47)
DEOK	($1.83)	($1.22)	($2.48)	($0.96)	($0.56)	($1.39)
DLCO	($1.79)	($1.17)	($2.47)	($0.95)	($0.60)	($1.34)
DPL	($1.61)	($0.78)	($2.50)	($1.05)	($0.65)	($1.46)
Dominion	($1.80)	($1.06)	($2.58)	($0.98)	($0.67)	($1.32)
EKPC	NA	NA	NA	($0.10)	($0.02)	($0.20)
JCPL	($1.45)	($0.55)	($2.48)	($1.18)	($1.05)	($1.34)
Met-Ed	($1.86)	($1.16)	($2.64)	($1.09)	($0.78)	($1.43)
PECO	($1.67)	($0.96)	($2.44)	($1.01)	($0.67)	($1.38)
PENELEC	($2.15)	($1.70)	($2.63)	($1.02)	($0.67)	($1.39)
PPL	($2.11)	($1.55)	($2.71)	($1.14)	($0.83)	($1.48)
PSEG	($1.54)	($0.53)	($2.69)	($0.96)	($0.64)	($1.33)
Pepco	($1.88)	($1.31)	($2.49)	($1.00)	($0.71)	($1.31)
RECO	($1.42)	($0.43)	($2.61)	($0.92)	($0.58)	($1.32)

Table 3-31 Day-ahead, average, zonal markup component (Adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)			2013 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.52)	$0.38	($1.49)	($0.68)	($0.47)	($0.92)
AEP	($0.90)	($0.31)	($1.52)	($0.66)	($0.37)	($0.97)
AP	($0.78)	($0.34)	($1.25)	($0.73)	($0.45)	($1.03)
ATSI	($0.93)	($0.36)	($1.54)	($0.66)	($0.37)	($0.98)
BGE	($0.75)	($0.15)	($1.40)	($0.70)	($0.50)	($0.92)
ComEd	($0.86)	($0.32)	($1.44)	($0.61)	($0.32)	($0.92)
DAY	($0.83)	($0.19)	($1.52)	($0.68)	($0.37)	($1.02)
DEOK	($0.80)	($0.21)	($1.45)	($0.63)	($0.33)	($0.96)
DLCO	($0.82)	($0.20)	($1.50)	($0.62)	($0.36)	($0.91)
DPL	($0.65)	$0.13	($1.49)	($0.72)	($0.42)	($1.03)
Dominion	($0.78)	($0.10)	($1.51)	($0.67)	($0.45)	($0.91)
EKPC	NA	NA	NA	($0.05)	$0.00	($0.11)
JCPL	($0.48)	$0.38	($1.47)	($0.81)	($0.70)	($0.94)
Met-Ed	($0.90)	($0.23)	($1.65)	($0.76)	($0.54)	($1.01)
PECO	($0.71)	($0.03)	($1.46)	($0.69)	($0.44)	($0.97)
PENELEC	($1.10)	($0.64)	($1.59)	($0.66)	($0.40)	($0.94)
PPL	($1.13)	($0.61)	($1.71)	($0.80)	($0.57)	($1.04)
PSEG	($0.56)	$0.41	($1.67)	($0.65)	($0.42)	($0.92)
Pepco	($0.83)	($0.30)	($1.41)	($0.70)	($0.50)	($0.91)
RECO	($0.43)	$0.52	($1.58)	($0.64)	($0.38)	($0.93)

Markup by Day-Ahead System Price Levels

Table 3-32 and Table 3-33 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-32 Average, day-ahead markup (By LMP category, unadjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($3.43)	24.9%	($1.89)	5.1%
$25 to $50	($2.75)	70.8%	($2.97)	83.9%
$50 to $75	$2.52	2.8%	$0.75	8.9%
$75 to $100	$6.96	0.7%	$0.03	1.2%
$100 to $125	$18.93	0.3%	$0.01	0.4%
$125 to $150	$4.54	0.1%	$0.00	0.1%
>= $150	$16.80	0.3%	($0.30)	0.4%

Table 3-33 Average, day-ahead markup (By LMP category, adjusted): January through September, 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.46)	24.9%	($1.06)	5.1%
$25 to $50	($1.35)	70.8%	($2.06)	83.9%
$50 to $75	$2.94	2.8%	$0.83	8.9%
$75 to $100	$7.19	0.7%	$0.10	1.2%
$100 to $125	$19.30	0.3%	($0.03)	0.4%
$125 to $150	$4.91	0.1%	$0.00	0.1%
>= $150	$16.85	0.3%	($0.30)	0.4%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[28] The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped for 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped for 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[29] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[30,31]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder. For example, if a generating station had two identical units with identical electrical impacts on the system, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. This recommendation is currently scheduled to be evaluated through the PJM stakeholder process in the fourth quarter of 2013.

FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[32]

Table 3-34 shows, by month, the number of FMUs and AUs in 2012 and 2013. For example, in January 2013, there were 18 FMUs and AUs in Tier 1, 17 FMUs and AUs in Tier 2, and 10 FMUs and AUs in Tier 3.

Table 3-34 Number of frequently mitigated units and associated units (By month): 2012 and January through September, 2013

	FMUs and AUs							
	2012				2013			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	21	52	99	18	17	10	45
February	26	22	47	95	18	11	12	41
March	25	17	47	89	18	8	12	38
April	23	17	46	86	16	5	15	36
May	23	14	47	84	11	5	15	31
June	22	13	48	83	24	8	12	44
July	25	11	50	86	19	15	19	53
August	25	23	43	91	14	25	20	59
September	17	6	33	56	11	22	31	64
October	10	18	14	42				
November	9	21	10	40				
December	14	17	10	41				

28 110 FERC ¶ 61,053 (2005).
29 OA, Schedule 1 § 6.4.2.
30 114 FERC ¶ 61, 076 (2006).
31 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

32 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria

Figure 3-5 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February, 2006.

Figure 3-5 Frequently mitigated units and associated units (By month): February, 2006 through September, 2013

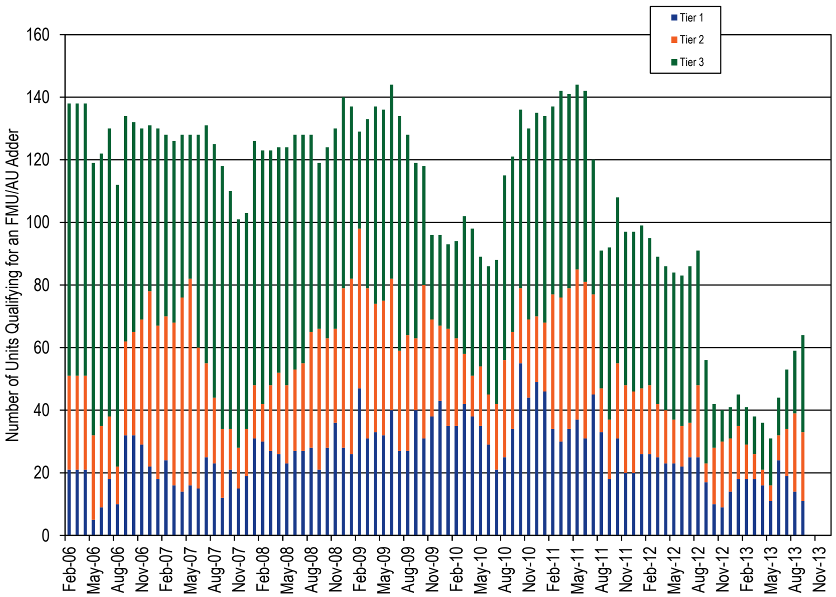


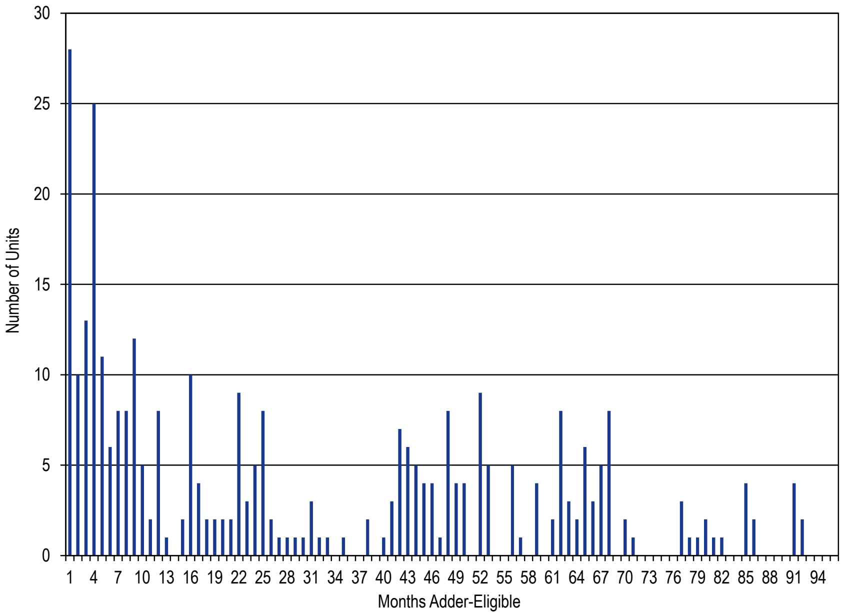
Table 3-35 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2012 and during the first nine months of 2013. Of the 81 units eligible in at least one month during the first nine months of 2013, 24 units (29.6 percent) were FMUs or AUs for all nine months, and 16 units (19.8 percent) qualified in only one month of 2013. The reduction in the total number of units qualifying for an FMU or AU adder resulted from the decrease in congestion, which was in turn the result of changes in fuel costs and changes in system topology.

Table 3-35 Frequently mitigated units and associated units total months eligible: 2012 and January through September, 2013

Months Adder-Eligible	FMU & AU Count	
	2012	2013
1	25	16
2	12	10
3	4	11
4	9	7
5	2	1
6	4	1
7	14	1
8	16	10
9	15	24
10	5	
11	2	
12	25	
Total	188	81

Figure 3-6 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through September 30, 2013, there have been 332 unique units that have qualified for an FMU adder in at least one month. Of these 332 units, no unit qualified for an adder in all potential months. Two units qualified in 92 of the 93 possible months, and 102 of the 332 units (30.7 percent) have qualified for an adder in more than half of the possible months.

Figure 3-6 Frequently mitigated units and associated units total months eligible: February, 2006 through September, 2013



Market Performance: Load and LMP

The PJM system load and average LMP reflect the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Load

PJM average real-time load in the first nine months of 2013 increased by 0.5 percent from the first nine months of 2012, from 88,687 MW to 89,123 MW. The PJM average real-time load in the first nine months of 2013 would have decreased by 0.2 percent from the first nine months of 2012, from 88,687 MW to 88,522 MW, if the EKPC Transmission Zone had not been included in the comparison.[33]

33 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

PJM average day-ahead load, including DECs and up-to congestion transactions, in the first nine months of 2013 increased by 9.5 percent from the first nine months of 2012, from 132,494 MW to 145,139 MW. The PJM average day-ahead load, including DECs and up-to congestion transactions, would have increased 9.1 percent from the first nine months of 2012, from 132,494 MW to 144,501 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead load growth was 1,800.0 percent higher than the real-time load growth because of the continued growth of up-to congestion transactions. If the first nine months of 2013 up-to congestion transactions had been held to the first nine months of 2012 levels, the day-ahead load, including DECs and up-to congestion transactions, would have decreased 0.5 percent instead of increasing 9.5 percent. The day-ahead load growth would have been 200.0 percent lower than the real-time load growth.

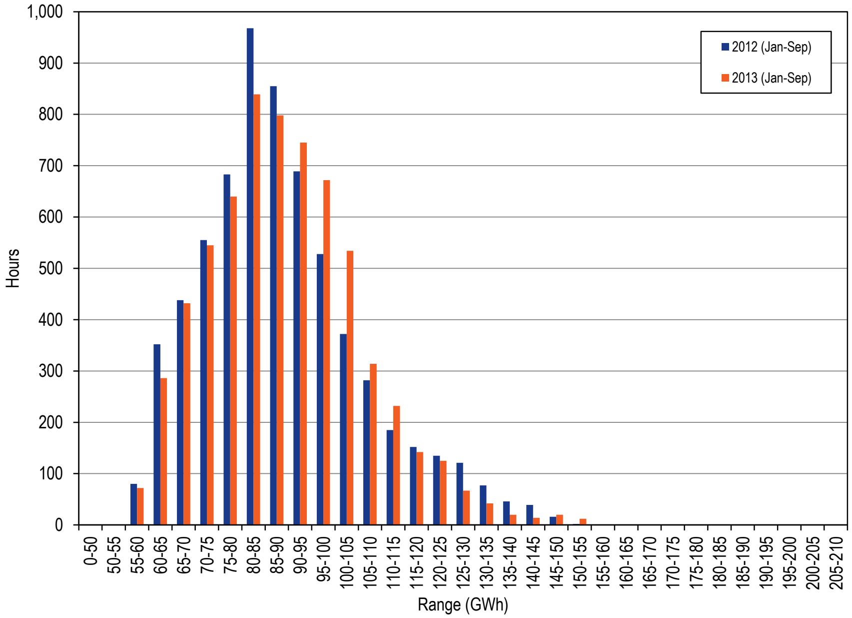
Real-Time Load

PJM Real-Time Load Duration

Figure 3-7 shows the hourly distribution of PJM real-time load for the first nine months of 2012 and 2013.[34]

34 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP" are based on PJM accounting load. See the *Technical Reference for PJM Markets*, Section 5, "Load Definitions," for detailed definitions of accounting load.

Figure 3-7 Distribution of PJM real-time accounting load: January through September of 2012 and 2013[35]



PJM Real-Time, Average Load

Table 3-36 presents summary real-time load statistics for the first nine months of each year during the 16 year period 1998 to 2013. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[36]

Table 3-36 PJM real-time average hourly load: January through September of 1998 through 2013[37]

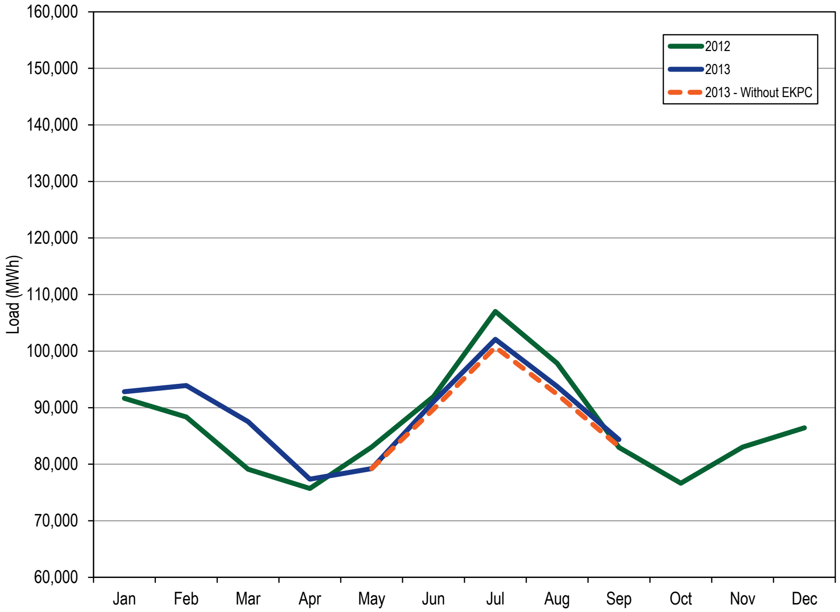
	PJM Real-Time Load (MWh)		Year-to-Year Change	
(Jan-Sep)	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	29,112	5,780	NA	NA
1999	30,236	6,306	3.9%	9.1%
2000	30,266	5,765	0.1%	(8.6%)
2001	31,060	6,156	2.6%	6.8%
2002	35,715	8,688	15.0%	41.1%
2003	37,996	7,187	6.4%	(17.3%)
2004	45,294	10,512	19.2%	46.3%
2005	78,235	17,541	72.7%	66.9%
2006	80,717	15,568	3.2%	(11.2%)
2007	83,114	15,386	3.0%	(1.2%)
2008	80,611	14,389	(3.0%)	(6.5%)
2009	76,954	13,879	(4.5%)	(3.5%)
2010	81,068	16,209	5.3%	16.8%
2011	83,762	17,604	3.3%	8.6%
2012	88,687	17,431	5.9%	(1.0%)
2013	89,123	16,384	0.5%	(6.0%)

PJM Real-Time, Monthly Average Load

Figure 3-7 compares the real-time, monthly average hourly loads in 2013 with those in 2012.

35 Each range on the vertical axis includes the start value and excludes the end value.
36 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.
37 The data used in the version of this table in the *2012 State of the Market Report for PJM: January through September* have been updated by PJM and the updates are included in this table.

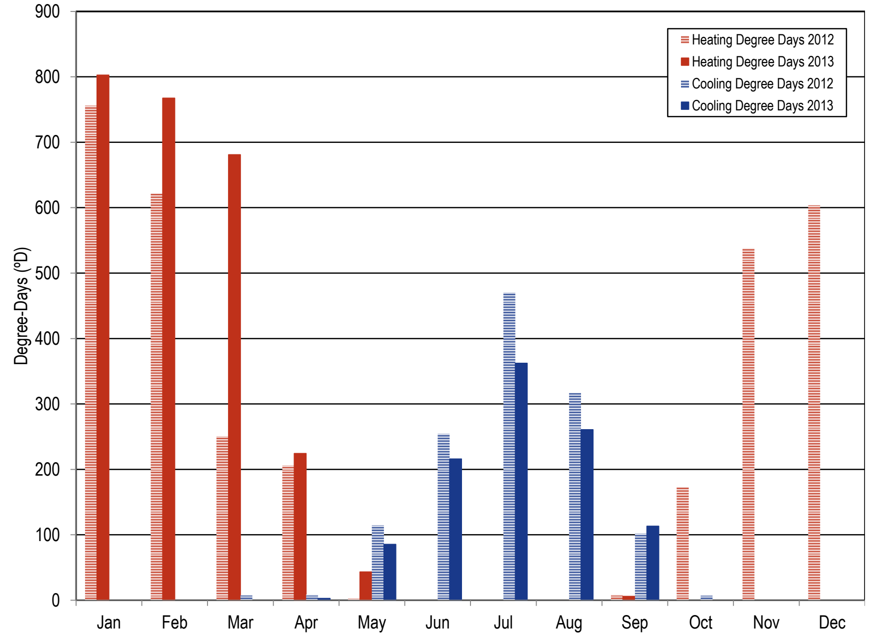
Figure 3-8 PJM real-time monthly average hourly load: January 2012 through September 2013



PJM real-time load is significantly affected by temperature. Figure 3-9 compares the total PJM monthly heating and cooling degree days in the first nine months of 2013 with those in 2012.[38] The figure shows that in the first nine months of 2013, the heating degree days were higher and the cooling degree days were lower than in the corresponding months of 2012, except for September.

38 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings).
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average daily temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting.
The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, ORD, ORF, PHL, PIT, RIC, ROA, SDF, TOL and WAL.

Figure 3-9 PJM Heating and Cooling Degree Days: January of 2012 through September of 2013



Day-Ahead Load

In the PJM Day-Ahead Energy Market, four types of financially binding demand bids are made and cleared:

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A decrement bid is a financial bid that can be submitted by any market participant.

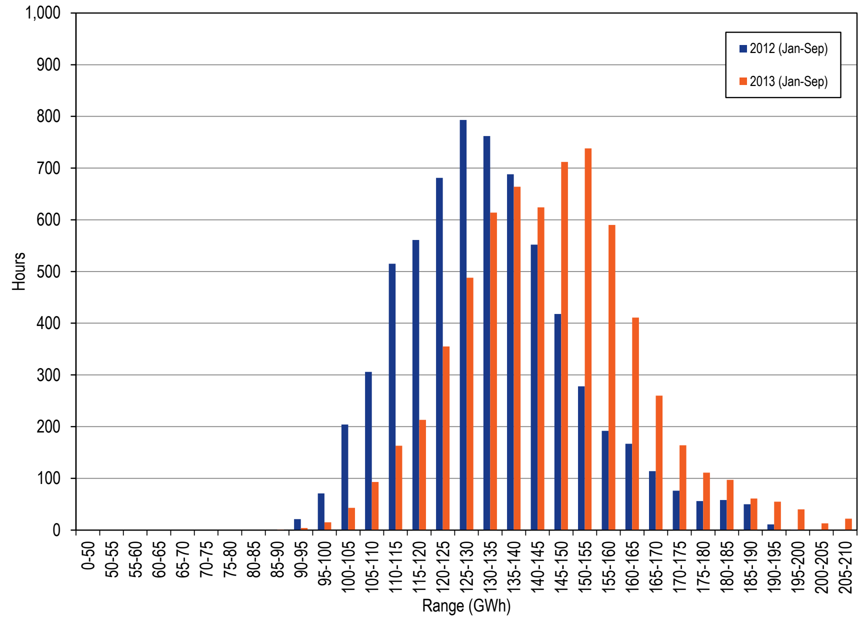
- **Up-to Congestion Transaction.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

PJM day-ahead load is the hourly total of the four types of cleared demand bids.[39]

PJM Day-Ahead Load Duration

Figure 3-10 shows the hourly distribution of PJM day-ahead load for the first nine months of 2012 and 2013.

Figure 3-10 Distribution of PJM day-ahead load: January through September of 2012 and 2013



39 Since an up-to congestion transaction is treated as analogous to a matched pair of INC offers and DEC bids, the DEC portion of the up-to congestion transaction contributes to the PJM day-ahead load, and the INC portion contributes to the PJM day-ahead generation.

PJM Day-Ahead, Average Load

Table 3-37 presents summary day-ahead load statistics for the first nine months of each year of the 13-year period 2001 to 2013.

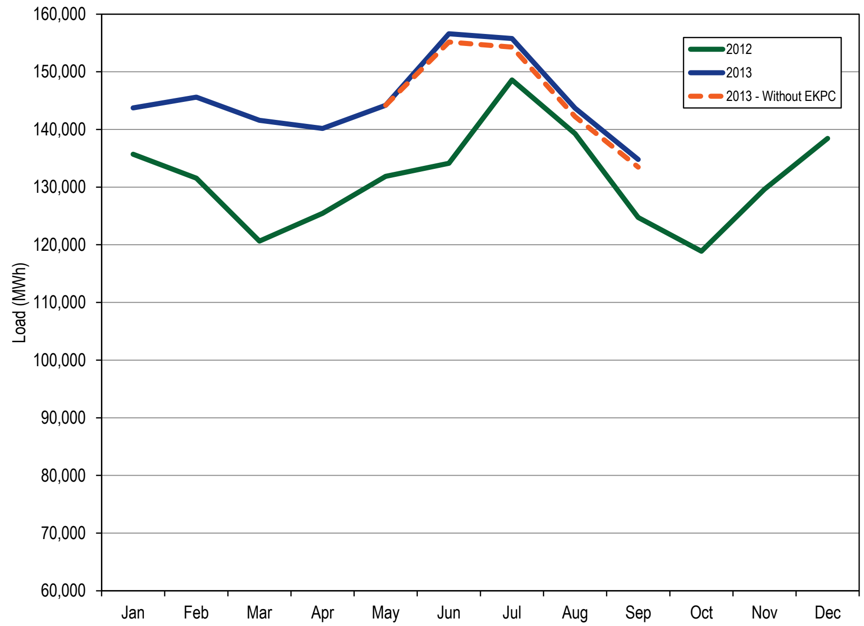
Table 3-37 PJM day-ahead average load: January through September of 2001 through 2013

	PJM Real-Time Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Sep)	Load	Up-to congestion	Total Load	Load	Up-to congestion	Total Load	Load	Up-to congestion	Total Load
2000	34,064	0	34,064	7,649	0	7,649	NA	NA	NA
2001	33,878	66	33,944	6,978	199	7,016	(0.5%)	NA	(0.4%)
2002	41,547	87	41,634	11,053	202	11,073	22.6%	32.2%	22.7%
2003	45,083	288	45,371	8,409	287	8,377	8.5%	230.4%	9.0%
2004	54,997	833	55,830	13,103	584	13,319	22.0%	189.4%	23.1%
2005	92,162	1,363	93,525	18,867	851	19,126	67.6%	63.6%	67.5%
2006	95,572	3,831	99,403	17,415	1,657	18,165	3.7%	181.1%	6.3%
2007	102,742	4,553	107,295	17,075	1,535	17,580	7.5%	18.8%	7.9%
2008	97,506	6,080	103,586	16,051	1,830	16,618	(5.1%)	33.6%	(3.5%)
2009	89,680	6,340	96,020	15,756	2,018	16,995	(8.0%)	4.3%	(7.3%)
2010	92,683	12,335	105,018	17,769	8,637	22,972	3.3%	94.5%	9.4%
2011	92,828	20,896	113,724	19,456	5,481	22,444	0.2%	69.4%	8.3%
2012	94,857	37,637	132,494	18,419	5,706	18,115	2.2%	80.1%	16.5%
2013	94,252	50,888	145,139	16,674	10,509	18,667	(0.6%)	35.2%	9.5%

PJM Day-Ahead, Monthly Average Load

Figure 3-11 compares the day-ahead, monthly average hourly loads of 2013 with those of 2012.

Figure 3-11 PJM day-ahead monthly average hourly load: January 2012 through September 2013



Real-Time and Day-Ahead Load

Table 3-38 presents summary statistics for the first nine months of 2012 and 2013 day-ahead and real-time loads.

Table 3-38 Cleared day-ahead and real-time load (MWh): January through September of 2012 and 2013[40]

		Day Ahead					Real Time	Average Difference	
	(Jan-Sep)	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bids	Cleared Up-to Congestion	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bids Minus Up-to Congestion
Average	2012	85,748	756	8,354	37,637	132,494	88,687	43,807	(2,184)
	2013	85,893	1,156	7,204	50,888	145,139	89,123	56,016	(2,075)
Median	2012	83,361	725	8,019	36,844	130,970	86,125	44,845	(18)
	2013	84,729	1,184	6,925	51,045	144,982	87,586	57,396	(574)
Standard Deviation	2012	17,044	142	1,856	5,706	18,115	17,431	684	(6,879)
	2013	15,592	254	1,505	10,509	18,667	16,384	2,284	(9,730)
Peak Average	2012	95,511	810	9,347	37,608	143,276	98,401	44,875	(2,080)
	2013	95,790	1,248	7,956	51,272	156,266	99,025	57,241	(1,987)
Peak Median	2012	91,277	781	9,084	36,899	139,945	93,938	46,007	24
	2013	93,964	1,306	7,582	52,023	154,283	97,004	57,279	(2,325)
Peak Standard Deviation	2012	15,176	143	1,750	5,551	15,563	15,601	(38)	(7,339)
	2013	12,954	272	1,467	9,793	15,569	13,993	1,576	(9,684)
Off-Peak Average	2012	77,186	708	7,483	37,663	123,039	80,169	42,870	(2,275)
	2013	77,238	1,075	6,546	50,552	135,411	80,465	54,946	(2,152)
Off-Peak Median	2012	74,624	684	7,138	36,794	121,287	77,560	43,727	(205)
	2013	75,784	1,104	6,308	50,254	134,578	78,761	55,816	(747)
Off-Peak Standard Deviation	2012	13,653	123	1,469	5,840	14,567	14,198	369	(6,940)
	2013	12,184	206	1,199	11,087	15,440	13,087	2,353	(9,934)

40 The data used in the version of this table in the *2012 State of the Market Report for PJM: January through June* have been updated by PJM and the updates are accounted for in this table.

Figure 3-12 shows the average hourly cleared volumes of day-ahead load (fixed-demand bids and price-sensitive bids), and day-ahead load plus each component of day-ahead demand, including decrement bids, up-to congestion transactions and exports.

Figure 3-12 Day-ahead and real-time loads (Average hourly volumes): January through September of 2013

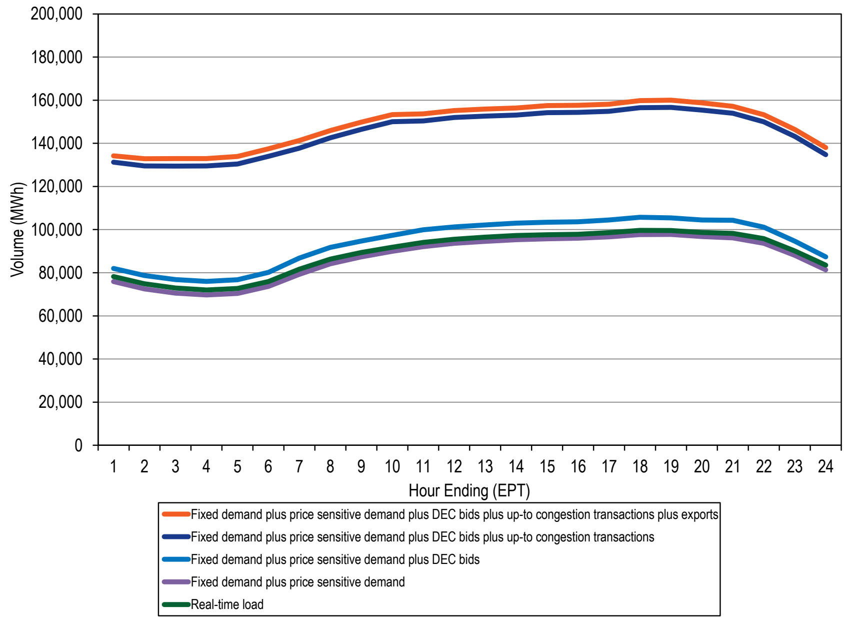
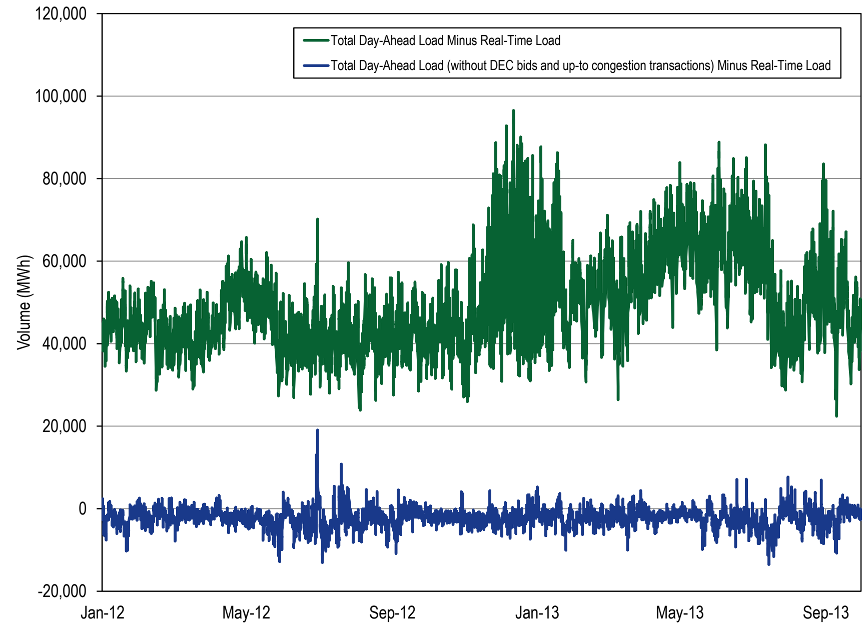


Figure 3-13 shows the difference between the day-ahead and real-time average daily loads in 2012 through the first nine months of 2013.

Figure 3-13 Difference between day-ahead and real-time loads (Average daily volumes): January 2012 through September of 2013



Real-Time and Day-Ahead Generation

PJM average real-time generation in the first nine months of 2013 increased by 0.1 percent from the first nine months of 2012, from 90,367 MW to 90,432 MW. The PJM average real-time generation in the first nine months of 2013 would have decreased by 0.5 percent from the first nine months of 2012, from 90,367 MW to 89,910 MW, if the EKPC Transmission Zone had not been included in the comparison.[41]

41 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

PJM average day-ahead generation in the first nine months of 2013, including INCs and up-to congestion transactions, increased by 9.8 percent from the first nine months of 2012, from 135,213 MW to 148,489 MW. The PJM average day-ahead generation in the first nine months of 2013, including INCs and up-to congestion transactions, would have increased 9.4 percent from the first nine months of 2012, from 135,213 MW to 147,895 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead generation growth was 9,700.0 percent higher in the first nine months of 2013 than the real-time generation growth in the first nine months of 2012 because of the continued growth of up-to congestion transactions. If the first nine months of 2013 up-to congestion transactions had been held to first nine months of 2012 levels, the day-ahead generation, including INCs and up-to congestion transactions, would have increased 0.0 percent instead of 9.8 percent and day-ahead generation growth would have been 80.0 percent lower than the real-time generation growth.

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.

In the Day-Ahead Energy Market, four types of financially binding generation offers are made and cleared:[42]

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh from a specific unit, including a minimum MWh level from a specific unit that also has a dispatchable component above the minimum.[43]
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. An increment offer is a financial offer that can be submitted by any market participant.
- **Up-to Congestion Transaction.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

Table 3-39 presents summary real-time generation statistics for the first nine months of each year for the 11-year period from 2003 through 2013.

42 All references to day-ahead generation and increment offers are presented in cleared MWh in the "Real-Time and Day-Ahead Generation" portion of the *2013 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Energy Market."
43 The definition of self-scheduled is based on the PJM "eMKT User Guide" (July, 2013), pp. 47-51.

Table 3-39 PJM real-time average hourly generation: January through September of 2003 through 2013

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
(Jan-Sep)	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	37,211	6,556	NA	NA
2004	45,888	11,035	23.3%	68.3%
2005	81,095	16,710	76.7%	51.4%
2006	84,260	14,696	3.9%	(12.1%)
2007	87,297	14,853	3.6%	1.1%
2008	85,241	14,203	(2.4%)	(4.4%)
2009	78,850	14,242	(7.5%)	0.3%
2010	84,086	16,346	6.6%	14.8%
2011	86,966	17,369	3.4%	6.3%
2012	90,367	16,893	3.9%	(2.7%)
2013	90,432	15,792	0.1%	(6.5%)

Table 3-40 presents summary day-ahead generation statistics for the first nine months of each year of the 11-year period from 2003 through 2013.

Table 3-40 PJM day-ahead average hourly generation: January through September of 2003 through 2013

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Sep)	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation
2003	39,736	288	40,024	9,113	287	9,079	NA	NA	NA
2004	55,270	833	56,103	13,158	584	13,380	39.1%	189.4%	40.2%
2005	93,074	1,363	94,437	18,401	851	18,671	68.4%	63.6%	68.3%
2006	97,056	3,831	100,888	17,304	1,657	18,061	4.3%	181.1%	6.8%
2007	105,748	4,553	110,300	17,092	1,535	17,561	9.0%	18.8%	9.3%
2008	101,287	6,080	107,367	16,015	1,830	16,601	(4.2%)	33.6%	(2.7%)
2009	92,187	6,340	98,527	16,220	2,018	17,462	(9.0%)	4.3%	(8.2%)
2010	95,974	12,335	108,309	18,086	8,637	23,295	4.1%	94.5%	9.9%
2011	96,092	20,896	116,988	19,705	5,481	22,722	0.1%	69.4%	8.0%
2012	97,576	37,637	135,213	18,929	5,706	18,553	1.5%	80.1%	15.6%
2013	97,602	50,888	148,489	17,044	10,509	18,858	0.0%	35.2%	9.8%

Table 3-41 presents summary statistics for the first nine months of 2012 and 2013 for day-ahead and real-time generation.

Table 3-41 Day-ahead and real-time generation (MWh): January through September of 2012 and 2013

		Day Ahead				Real Time	Average Difference	
	(Jan-Sep)	Cleared Generation	Cleared INC Offers	Cleared Up-to Congestion	Cleared Generation Plus INC Offers Plus Up-to Congestion	Generation	Cleared Generation	Cleared Generation Plus INC Offers Plus Up-to Congestion
Average	2012	91,382	6,194	37,637	135,213	90,367	1,015	44,846
	2013	92,323	5,279	50,888	148,489	90,432	1,891	58,057
Median	2012	88,873	6,191	36,844	133,659	87,665	1,207	45,993
	2013	91,378	5,292	51,045	148,344	89,341	2,037	59,002
Standard Deviation	2012	18,736	906	5,706	18,553	16,893	1,843	1,659
	2013	16,953	868	10,509	18,858	15,792	1,160	3,066
Peak Average	2012	102,016	6,547	37,608	146,171	99,382	2,635	46,789
	2013	102,879	5,551	51,272	159,702	99,804	3,075	59,898
Peak Median	2012	97,816	6,477	36,899	142,800	95,406	2,410	47,393
	2013	100,661	5,620	52,023	157,635	98,051	2,610	59,584
Peak Standard Deviation	2012	16,523	721	5,551	15,938	15,366	1,157	572
	2013	13,985	776	9,793	15,691	13,518	467	2,173
Off-Peak Average	2012	82,057	5,884	37,663	125,604	82,461	(405)	43,142
	2013	83,093	5,040	50,552	138,686	82,238	856	56,448
Off-Peak Median	2012	79,731	5,810	36,794	123,948	80,263	(532)	43,685
	2013	81,594	5,001	50,254	137,872	80,728	866	57,144
Off-Peak Standard Deviation	2012	15,277	939	5,840	15,023	13,960	1,318	1,064
	2013	13,604	874	11,087	15,662	12,797	808	2,866

Figure 3-14 shows the average hourly cleared volumes of day-ahead generation, and day-ahead generation plus each component of day-ahead supply, including increment offers, up-to congestion transactions and imports, and the real-time generation.[44]

44 Generation data are the sum of MWh at every generation bus in PJM with positive output.

Figure 3-14 Day-ahead and real-time generation (Average hourly volumes): January through September of 2013

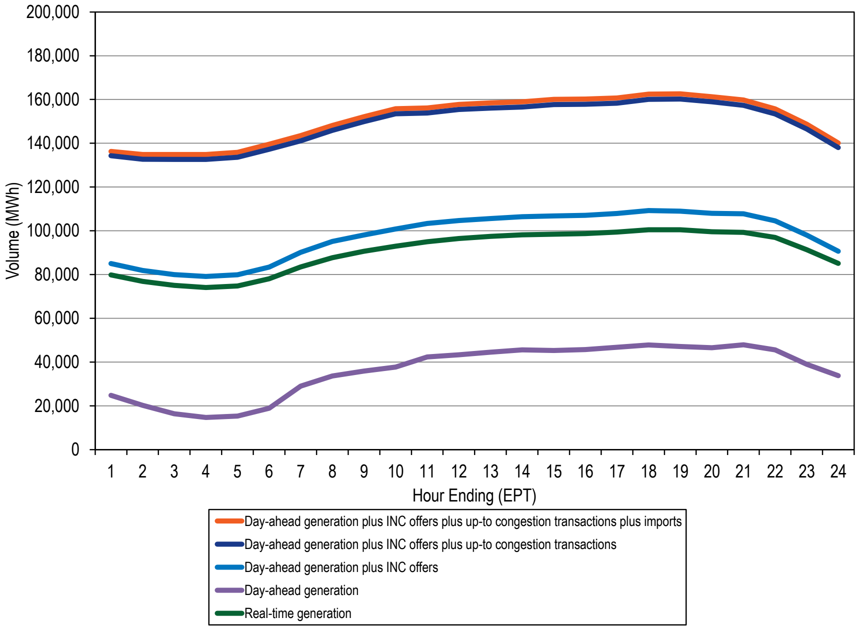


Figure 3-15 shows the difference between the day-ahead and real-time average daily generation in 2012 through the first nine months of 2013.

Figure 3-15 Difference between day-ahead and real-time generation (Average daily volumes): January 2012 through September of 2013

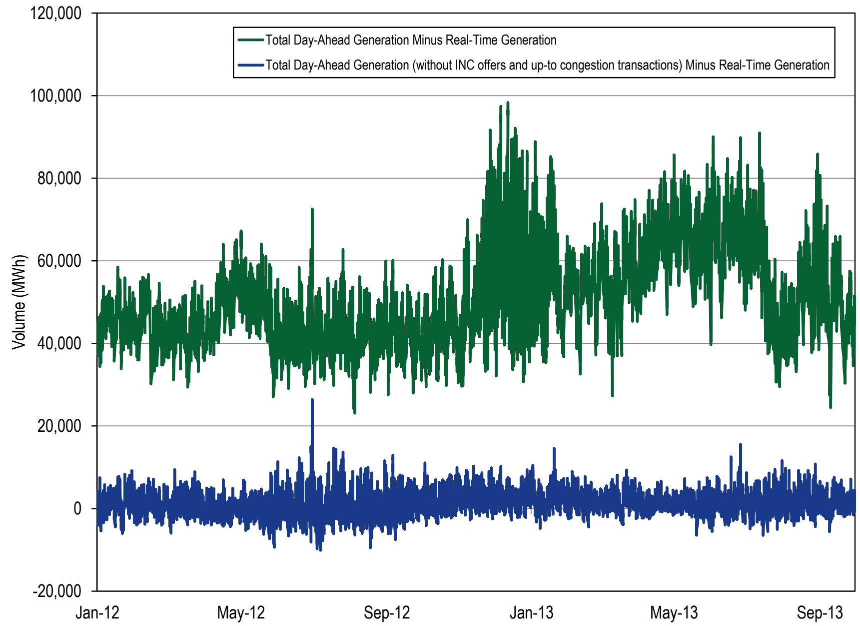


Figure 3-16 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2013. Table 3-42 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2012 and 2013. Figure 3-16 is color coded on a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load.

Figure 3-16 Map of PJM real-time generation less real-time load by zone: January through September of 2013[45]

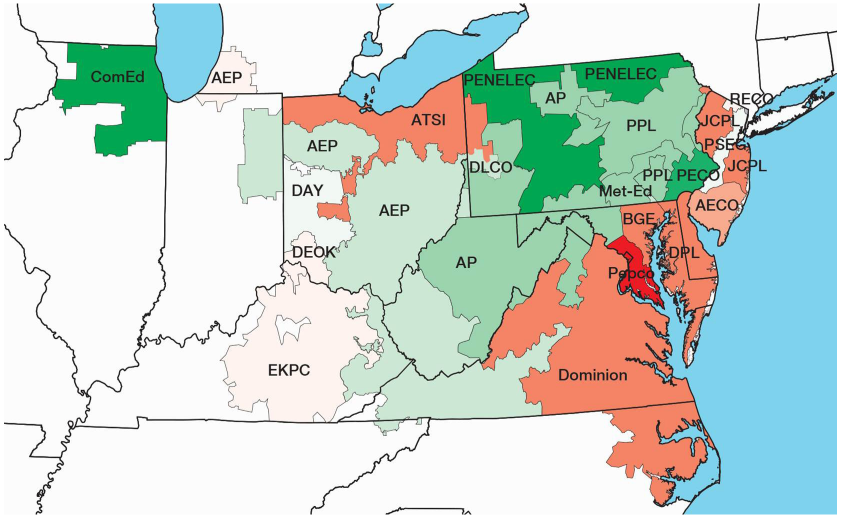


Table 3-42 PJM real-time generation less real-time load by zone (GWh): January through September of 2013

	Zonal Generation and Load (GWh)					
	2012 (Jan-Sep)			2013 (Jan-Sep)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	1,551.2	8,304.5	(6,753.3)	1,720.2	8,013.9	(6,293.7)
AEP	107,865.8	99,065.9	8,799.8	99,790.3	97,582.4	2,207.9
AP	36,952.7	34,638.2	2,314.5	42,595.9	35,282.2	7,313.7
ATSI	45,187.6	50,733.4	(5,545.8)	41,393.9	50,220.1	(8,826.2)
BGE	15,591.1	24,915.2	(9,324.1)	15,944.6	24,500.6	(8,556.0)
ComEd	97,385.1	76,462.7	20,922.4	94,423.0	74,585.7	19,837.4
DAY	11,907.1	12,780.4	(873.3)	12,891.4	12,587.0	304.4
DEOK	14,484.4	20,326.6	(5,842.2)	18,602.4	20,209.2	(1,606.8)
DLCO	13,486.1	11,452.9	2,033.2	13,962.7	11,109.6	2,853.1
Dominion	60,066.3	69,863.7	(9,797.4)	61,604.3	71,237.2	(9,632.9)
DPL	6,679.8	13,936.0	(7,256.2)	5,874.7	14,084.8	(8,210.2)
EKPC	NA	NA	NA	3,420.7	3,937.2	(516.5)
JCPL	10,533.5	17,595.2	(7,061.7)	8,523.9	17,636.1	(9,112.2)
Met-Ed	15,887.5	11,398.2	4,489.2	15,490.1	11,332.1	4,158.0
PECO	45,863.5	30,393.7	15,469.8	45,148.4	30,480.7	14,667.8
PENELEC	28,821.9	12,818.4	16,003.5	32,773.1	12,889.7	19,883.4
Pepco	8,842.0	23,600.3	(14,758.4)	6,993.3	23,260.3	(16,266.9)
PPL	37,283.8	29,900.5	7,383.3	36,462.3	30,328.6	6,133.7
PSEG	35,773.7	33,754.0	2,019.7	34,804.9	33,390.7	1,414.2
RECO	0.0	1,179.3	(1,179.3)	0.0	1,177.6	(1,177.6)

Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices.[46] PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion. Real-Time and Day-Ahead Energy Market load-weighted prices were 13.5 percent and 15.1 percent higher in the first nine months of 2013 than in the first nine months of 2012 as a result of higher fuel costs and higher demand.[47] Natural

45 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20130601-lmp-bus-model.ashx>.

46 See the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

47 There was an average increase of 2.5 heating degree days and an average reduction of 0.8 cooling degree days in the first nine months of 2013 compared to the first nine months of 2012 which meant overall increased demand.

gas prices were higher, particularly in eastern zones, while coal prices were relatively constant. The fuel-cost-adjusted, load weighted LMP in the first nine months of 2013 shows that the mix of fuel types and fuel costs was the primary driver of higher prices than would have occurred if fuel prices had remained at the same levels as in the first nine months of 2012.

PJM Real-Time Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 15.0 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.30 per MWh versus $32.45 per MWh. The load-weighted average LMP was 13.5 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.75 per MWh versus $35.02 per MWh.

The fuel cost adjusted, load weighted, average LMP for the first nine months of 2013 was 14.2 percent lower than the load weighted, average LMP for the first nine months of 2013. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 load weighted LMP would have been lower, $34.12 per MWh instead of the observed $39.75 per MWh.

PJM Day-Ahead Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 16.6 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.50 per MWh versus $32.16 per MWh. The load-weighted average LMP was 15.1 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.49 per MWh versus $34.29 per MWh.[48]

Real-Time LMP

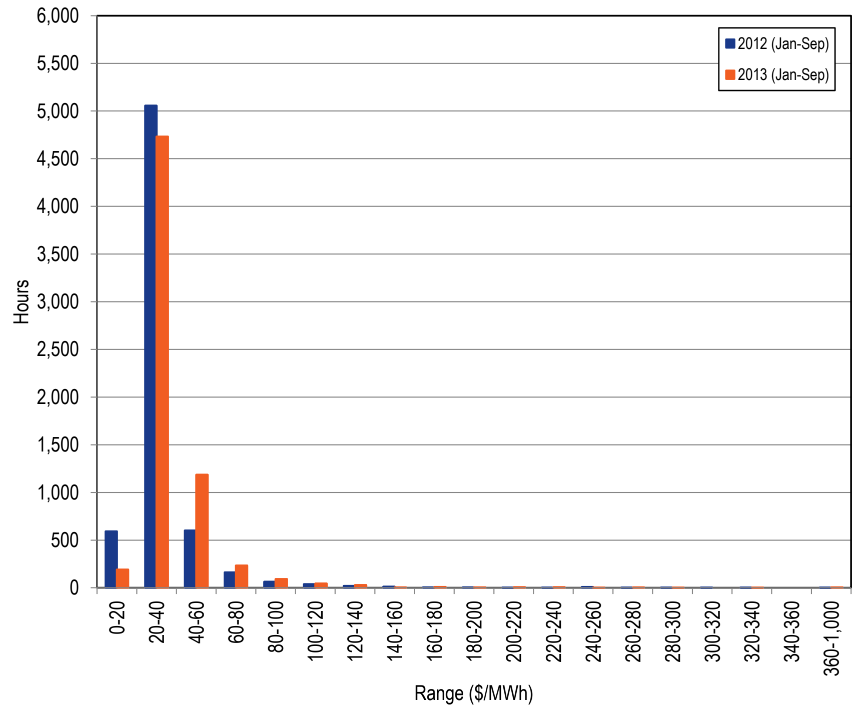
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[49]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-17 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2012 and 2013.

Figure 3-17 Average LMP for the PJM Real-Time Energy Market: January through September of 2012 and 2013



48 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

49 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Real-Time LMP.

PJM Real-Time, Average LMP

Table 3-43 shows the PJM real-time, average LMP for the first nine months of each year of the 16-year period 1998 to 2013.[50]

Table 3-43 PJM real-time, average LMP (Dollars per MWh): January through September of 1998 through 2013

	Real-Time LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	15.0%	12.7%	4.1%

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-44 shows the PJM real-time, load-weighted, average LMP for the first nine months of each year of the 16-year period 1998 to 2013.

50 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

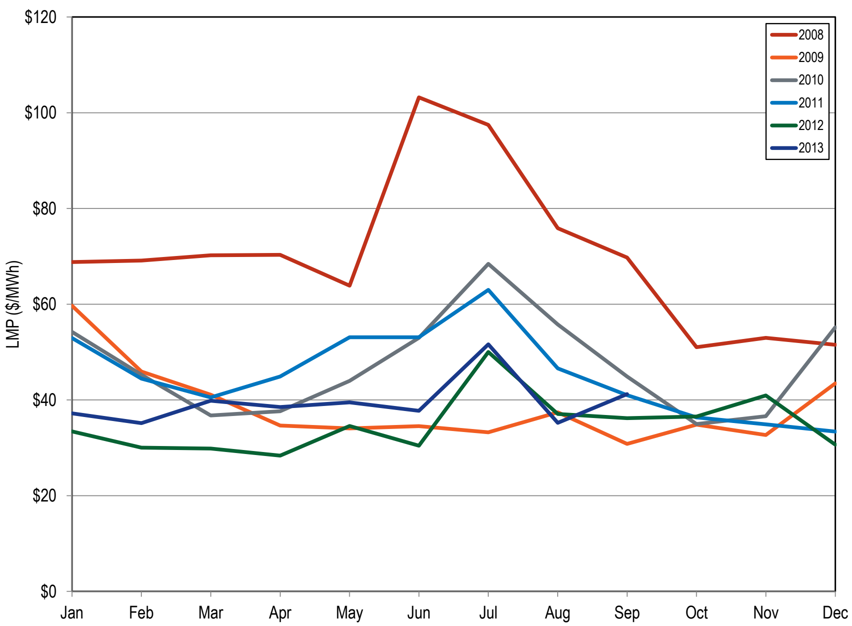
Table 3-44 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through September of 1998 through 2013

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	13.5%	12.6%	4.0%

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 3-18 shows the PJM real-time, monthly, load-weighted LMP from 2008 through the first nine months of 2013.

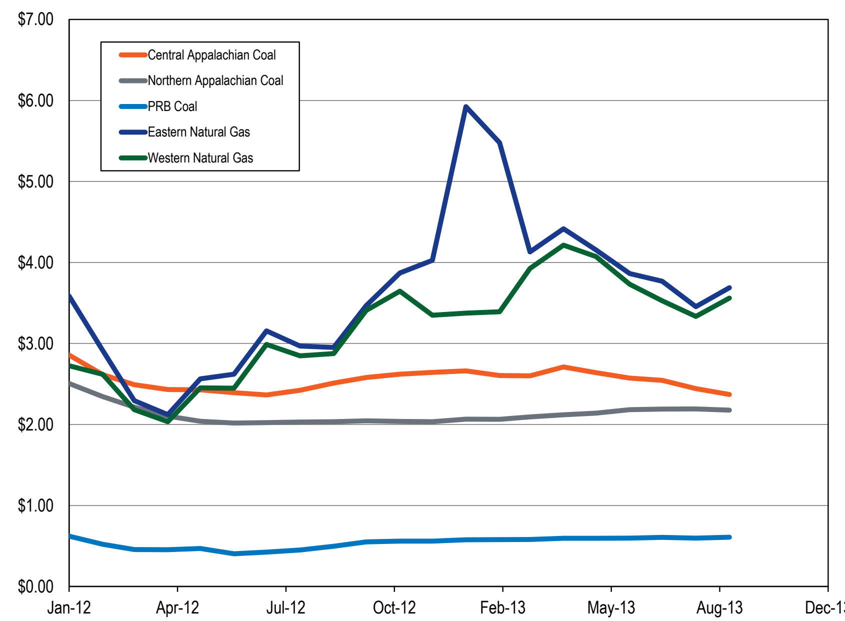
Figure 3-18 PJM real-time, monthly, load-weighted, average LMP: January 2008 through September of 2013



Fuel Price Trends and LMP

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Natural gas, especially in the eastern part of PJM increased in price in the first nine months of 2013. Comparing prices in the first nine months of 2013 to the first nine months of 2012, the price of Northern Appalachian coal was 0.4 percent lower; the price of Central Appalachian coal was 2.8 percent higher; the price of Powder River Basin coal was 24.1 percent higher; the price of eastern natural gas was 54.0 percent higher; and the price of western natural gas was 43.0 percent higher. Figure 3-19 shows monthly average spot fuel prices for 2012 and the first nine months of 2013.[51] Natural gas prices were above coal prices in the first nine months of 2013, with prices above $10/MMBtu for some days.

Figure 3-19 Spot average fuel price comparison with fuel delivery charges: 2012 and January through September 2013 ($/MMBtu)



51 Eastern natural gas and Western natural gas prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Figure 3-20 shows the marginal cost of generation in dollars per MWh. Marginal costs consist of fuel costs, fuel transportation costs, variable operations and maintenance adders, and emissions costs. The marginal cost of generation from a new entrant combined cycle was above the cost of a new entrant coal plant, but below the marginal cost of the average existing PJM sub-critical coal plant.

Figure 3-20 Marginal cost of generation of CP, CT, CC, and PJM average heat rate sub-critical coal plant: 2009 through September 2013 ($/MWh)

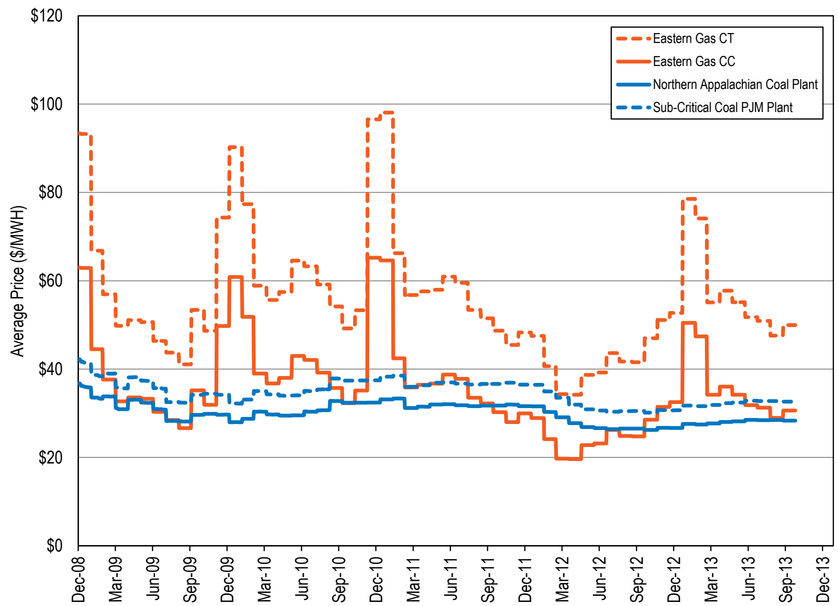


Table 3-45 compares the first nine months of 2013 PJM real-time fuel cost adjusted, load weighted, average LMP to the first nine months of 2012 load-weighted, average LMP. The fuel cost adjusted, load weighted, average LMP for the first nine months of 2013 was 14.2 percent lower than the load weighted, average LMP for the first nine months of 2013. The real-time, fuel cost adjusted, load weighted, average LMP for the first nine months of 2013 was 2.6 percent lower than the load weighted LMP for the first nine months of 2012. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 load weighted LMP would have been lower, $34.12 per MWh instead of the observed $39.75 per MWh. The mix of fuel types and fuel costs in 2013 were the primary driver of higher prices in 2013.

Table 3-45 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2013 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$39.75	$34.12	(14.2%)
	2012 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$35.02	$34.12	(2.6%)
	2012 Load-Weighted LMP	2013 Load-Weighted LMP	Change
Average	$35.02	$39.75	13.5%

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five-minute-ahead forecast of the system conditions. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose PJM system's load-weighted LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2.

The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[52]

Prior to the implementation of scarcity pricing on October 1, 2012, LMPs calculated based on SCED were modified ex-post (five minutes) to account for realized system conditions. This is sometimes referred to as an ex-post LMP calculation. The extent to which the ex-post LMP in a five-minute interval deviated from the LMP calculated by SCED (ex-ante LMP) reflected the change in system conditions between the time when the dispatch was solved, and the end of the five-minute interval. The contribution of this deviation to real-time LMPs is shown as the LPA-SCED differential. Starting with the October 1, 2012, implementation of scarcity pricing, PJM eliminated ex-post pricing and relies entirely on ex-ante pricing. After October 1, 2012, real-time LMPs are based solely on the interval's most recent SCED solution.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes energy and ancillary services. In periods when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the lost opportunity cost of the lowered generation and the associated incremental cost to maintain reserves. The cost of dispatching energy resources down to provide reserves is the Ancillary Service redispatch cost.

The components of LMP are shown in Table 3-46, including markup using unadjusted cost offers.[53] (Numbers in parentheses in the table are negative.) Table 3-46 shows that for the first nine months of 2013, 46.1 percent of the load-weighted LMP was the result of coal costs, 28.3 percent was the result of gas costs and 0.65 percent was the result of the cost of emission allowances. Markup was -$1.21 per MWh. In the first nine months of 2012, 54.3 percent of the load-weighted LMP was the result of coal costs, 23.4 percent was the result of gas costs and 0.59 percent was the result of the cost of emission allowances. Markup was -$1.23. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP rather than all of the components of the offers of units burning that fuel.

52 New Jersey withdrew from RGGI, effective January 1, 2012.

53 These components are explained in the *Technical Reference for PJM Markets*, Section 7 "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-46 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: January through September 2013 and 2012

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$19.01	54.3%	$18.33	46.1%
Gas	$8.20	23.4%	$11.24	28.3%
Ten Percent Adder	$3.49	10.0%	$3.67	9.2%
VOM	$2.57	7.3%	$2.34	5.9%
NA	$0.80	2.3%	$2.07	5.2%
Oil	$1.97	5.6%	$1.61	4.0%
FMU Adder	$0.12	0.3%	$0.98	2.5%
LPA Rounding Difference	$0.11	0.3%	$0.48	1.2%
Emergency DR Adder	$0.00	0.0%	$0.22	0.6%
Ancillary Service Redispatch cost	$0.00	0.0%	$0.17	0.4%
CO_2 Cost	$0.10	0.3%	$0.15	0.4%
NO_x Cost	$0.09	0.3%	$0.10	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.03	0.1%	$0.00	0.0%
Increase Generation Adder	$0.07	0.2%	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.01	0.0%	$0.00	0.0%
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%
Wind	($0.06)	(0.2%)	($0.00)	(0.0%)
Decrease Generation Adder	($0.27)	(0.8%)	($0.14)	(0.4%)
LPA-SCED Differential	($0.05)	(0.1%)	($0.27)	(0.7%)
Markup	($1.23)	(3.5%)	($1.21)	(3.0%)
Total	$35.02	100.0%	$39.75	100.0%

All generating units, including coal units, are allowed to include a ten percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions.

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-46 and Table 3-50), markup is simply the difference between the price offer and the cost offer. In the second approach

(Table 3-47 and Table 3-51), the 10 percent markup is removed from the cost offers of coal units. Coal units do not face the same cost uncertainty as gas-fired CTs. Actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer.

The components of LMP are shown in Table 3-47, including markup using adjusted cost offers.

Table 3-47 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: January through September 2013 and 2012

	2012 (Jan-Sep)		2013 (Jan-Sep)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$19.17	54.8%	$18.58	46.8%
Gas	$8.20	23.4%	$11.25	28.3%
VOM	$2.59	7.4%	$2.36	5.9%
Ten Percent Adder	$1.46	4.2%	$2.06	5.2%
NA	$0.80	2.3%	$1.85	4.6%
Oil	$1.97	5.6%	$1.61	4.0%
FMU Adder	$0.12	0.3%	$0.86	2.2%
LPA Rounding Difference	$0.11	0.3%	$0.70	1.8%
Markup	$0.62	1.8%	$0.27	0.7%
Emergency DR Adder	$0.00	0.0%	$0.22	0.6%
Ancillary Service Redispatch cost	$0.00	0.0%	$0.17	0.4%
CO_2 Cost	$0.10	0.3%	$0.15	0.4%
NO_x Cost	$0.09	0.3%	$0.10	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.03	0.1%	$0.00	0.0%
Increase Generation Adder	$0.07	0.2%	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.01	0.0%	$0.00	0.0%
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%
Wind	($0.06)	(0.2%)	($0.00)	(0.0%)
Decrease Generation Adder	($0.27)	(0.8%)	($0.14)	(0.4%)
LPA-SCED Differential	($0.05)	(0.1%)	($0.31)	(0.8%)
Total	$35.02	100.0%	$39.75	100.0%

Day-Ahead LMP

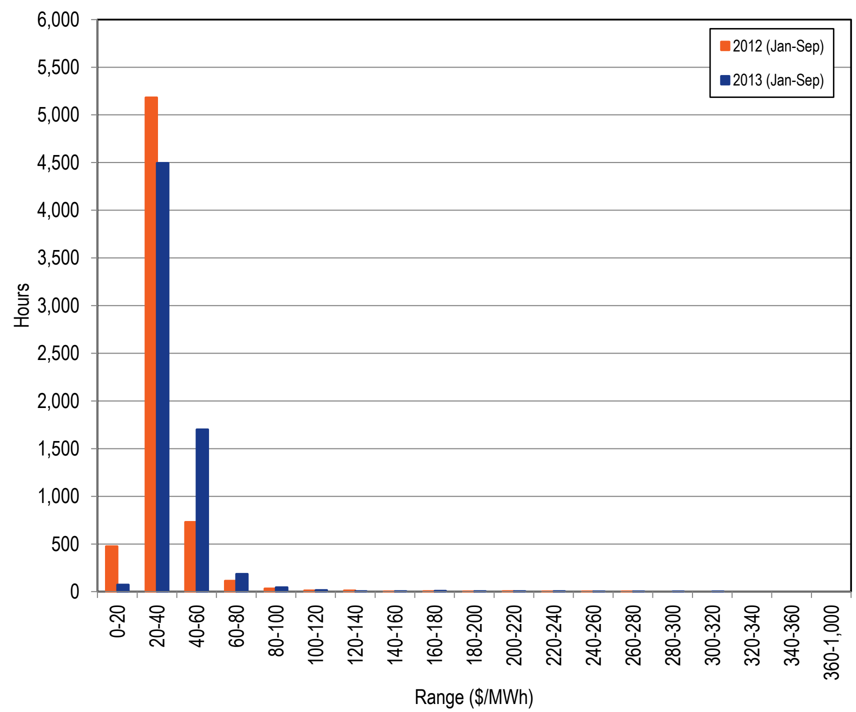
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[54]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-21 shows the hourly distribution of PJM day-ahead average LMP for the first nine months of 2012 and 2013.

Figure 3-21 Average LMP for the PJM Day-Ahead Energy Market: January through September of 2012 and 2013



54 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of Day-Ahead LMP.

PJM Day-Ahead, Average LMP

Table 3-48 shows the PJM day-ahead, average LMP for the first nine months of each year of the 13-year period 2001 to 2013.

Table 3-48 PJM day-ahead, average LMP (Dollars per MWh): January through September of 2001 through 2013

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	16.6%	15.3%	16.6%

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up-to congestion.

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-49 shows the PJM day-ahead, load-weighted, average LMP for the first nine months of each year of the 13-year period 2001 to 2013.

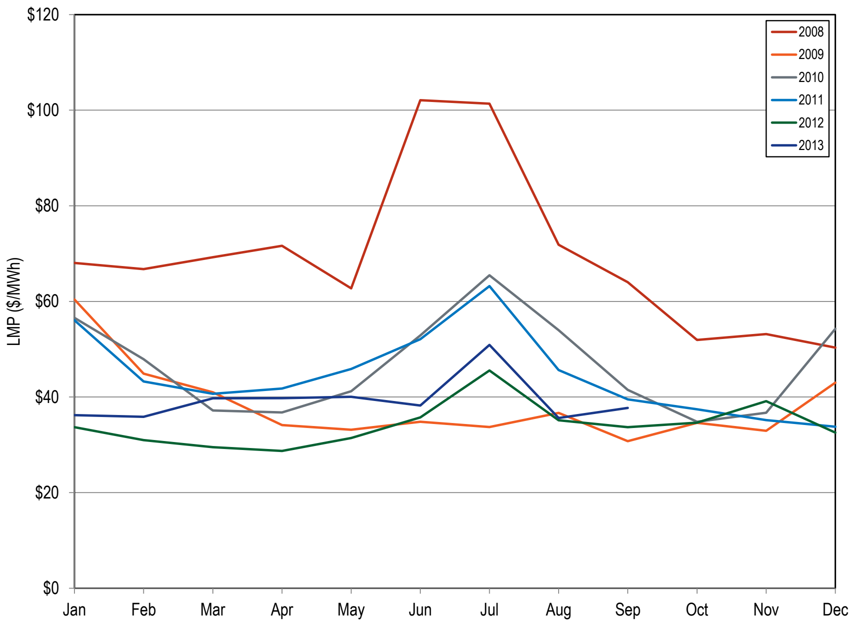
Table 3-49 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September of 2001 through 2013

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	15.1%	15.4%	16.3%

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 3-22 shows the PJM day-ahead, monthly, load-weighted LMP from 2008 through the first nine months of 2013.

Figure 3-22 Day-ahead, monthly, load-weighted, average LMP: January 2008 through September of 2013



Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder, Day-Ahead Scheduling Reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead market. To the extent that INCs, DECs or up-to congestion transactions are the marginal resource, they either directly or indirectly set price via their offers and bids. Such financial offers cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Day-Ahead Scheduling Reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_X, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_X and unit-specific emission rates for SO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[55]

The components of day ahead LMP are shown in Table 3-50, including markup using unadjusted cost offers. Table 3-50 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first nine months of 2013, 65.5 percent of the load-weighted LMP was the result of up-to congestion transactions, 15.0 percent was the result of the cost of coal and 7.1 percent was the result of the cost of gas. In the first nine months of 2012, 4.8 percent of the load-weighted LMP was the result of up-to congestion transactions, 38.9 percent was the result of the cost of coal and 12.9 percent was the result of the cost of gas.

55 New Jersey withdrew from RGGI, effective January 1, 2012.

Table 3-50 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): January through September 2012 and 2013[56]

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.34	38.9%	$5.93	15.0%
DEC	$8.40	24.5%	$2.31	5.8%
Gas	$4.41	12.9%	$2.79	7.1%
INC	$3.41	10.0%	$1.50	3.8%
10% Cost Adder	$1.98	5.8%	$0.94	2.4%
Up-to Congestion Transaction	$1.66	4.8%	$25.87	65.5%
VOM	$1.52	4.4%	$0.64	1.6%
Price Sensitive Demand	$0.58	1.7%	$0.06	0.2%
Dispatchable Transaction	$0.51	1.5%	$0.17	0.4%
Oil	$0.42	1.2%	$0.00	0.0%
DASR Offer Adder	$0.19	0.6%	$0.00	0.0%
CO_2	$0.06	0.2%	$0.02	0.0%
NO_x	$0.06	0.2%	$0.02	0.1%
SO_2	$0.01	0.0%	$0.00	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
Diesel	$0.00	0.0%	$0.00	0.0%
Wind	($0.00)	0.0%	($0.00)	(0.0%)
DASR LOC Adder	($0.41)	(1.2%)	$0.02	0.0%
Markup	($1.87)	(5.5%)	($1.00)	(2.5%)
FMU Adder	$0.00	0.0%	$0.06	0.2%
NA	$0.00	0.0%	$0.15	0.4%
Total	$34.29	100.0%	$39.49	100.0%

56 The NA in 2013 is $0.43. It is caused by bad savecase input files for March 5, 2013.

Table 3-51 shows the components of the PJM day ahead, annual, load-weighted average LMP.

Table 3-51 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): January through September 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.34	38.9%	$5.93	15.0%
DEC	$8.40	24.5%	$2.31	5.8%
Gas	$4.41	12.9%	$2.79	7.1%
INC	$3.41	10.0%	$1.50	3.8%
Up-to Congestion Transaction	$1.66	4.8%	$25.87	65.5%
VOM	$1.52	4.4%	$0.64	1.6%
10% Cost Adder	$0.96	2.8%	$0.61	1.6%
Price Sensitive Demand	$0.58	1.7%	$0.06	0.2%
Dispatchable Transaction	$0.51	1.5%	$0.17	0.4%
Oil	$0.42	1.2%	$0.00	0.0%
DASR Offer Adder	$0.19	0.6%	$0.00	0.0%
CO_2	$0.06	0.2%	$0.02	0.0%
NO_x	$0.06	0.2%	$0.02	0.1%
SO_2	$0.01	0.0%	$0.00	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
Diesel	$0.00	0.0%	$0.00	0.0%
Wind	($0.00)	0.0%	($0.00)	(0.0%)
DASR LOC Adder	($0.41)	(1.2%)	$0.02	0.0%
Markup	($0.85)	(2.5%)	($0.67)	(1.7%)
FMU Adder	$0.00	0.0%	$0.06	0.2%
NA	$0.00	0.0%	$0.15	0.4%
Total	$34.29	100.0%	$39.49	100.0%

Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Market and such offers and bids may be marginal, based on the way in which the PJM optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids and up-to congestion transactions as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Up-to congestion transactions may be submitted between any two buses eligible for FTRs.[57]

Figure 3-23 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in August 2013.

Figure 3-23 PJM day-ahead aggregate supply curves: 2013 example day

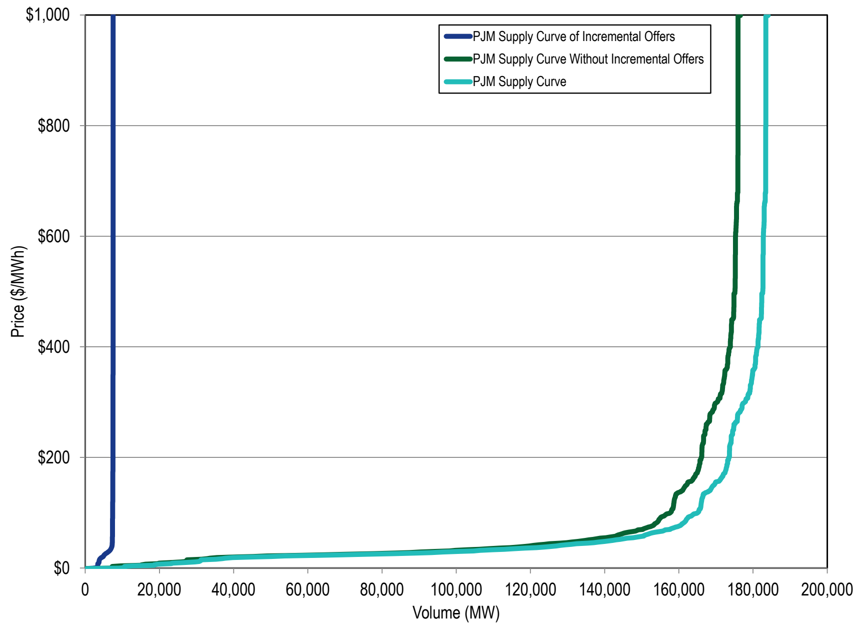


Table 3-52 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour for 2012 through the first nine months of 2013. Table 3-53 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour for 2012 through the first nine months of 2013. In the first nine months of 2013, the average submitted and cleared increment bid MW decreased 26.5 and 14.7 percent, and the average submitted and cleared decrement bid MW decreased 20.5 and 13.7 percent, compared to the first nine months of 2012. In the first nine months of 2013, the average up-to congestion submitted MW increased 57.2 percent and cleared MW increased 35.2 percent, compared to the first nine months of 2012. The increase in up-to congestion transactions displaced increment and decrement transactions.

Table 3-52 Hourly average volume of cleared and submitted INCs, DECs by month: January 2012 through September of 2013

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2012	Jan	6,781	10,341	91	455	9,031	12,562	111	428
2012	Feb	6,428	10,930	96	591	7,641	11,043	108	511
2012	Mar	5,969	9,051	90	347	7,193	10,654	112	362
2012	Apr	6,355	9,368	87	298	7,812	10,811	105	329
2012	May	6,224	8,447	80	271	8,785	11,141	109	316
2012	Jun	6,415	8,360	79	234	9,030	11,124	97	270
2012	Jul	6,485	8,270	81	285	8,981	11,121	112	349
2012	Aug	5,809	7,873	74	291	8,471	10,507	100	320
2012	Sep	5,274	7,509	78	313	8,192	10,814	109	381
2012	Oct	5,231	6,953	82	275	8,901	11,526	110	361
2012	Nov	5,423	6,944	67	190	8,678	11,758	102	289
2012	Dec	5,622	7,090	69	183	8,456	10,007	84	207
2012	Annual	6,001	8,428	81	311	8,431	11,089	105	343
2013	Jan	5,682	7,271	80	195	7,944	9,653	81	211
2013	Feb	5,949	7,246	61	130	7,689	8,942	75	165
2013	Mar	5,414	6,192	50	94	6,890	7,907	65	140
2013	Apr	5,329	6,179	56	108	6,597	7,732	63	145
2013	May	5,415	6,651	57	130	7,036	8,803	74	185
2013	Jun	5,489	7,031	64	187	7,671	9,768	88	258
2013	Jul	5,374	6,710	60	173	7,566	9,786	89	267
2013	Aug	4,633	6,169	62	179	6,818	8,295	78	195
2013	Sep	4,262	5,464	60	191	6,646	8,400	82	233
2013	Annual	5,283	6,546	61	154	7,206	8,810	77	200

57 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up-to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*,"<<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>>

Table 3-53 Hourly average of cleared and submitted up-to congestion bids by month: January 2012 through September 2013

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2012	Jan	37,469	102,762	805	1,950
2012	Feb	37,132	106,741	830	2,115
2012	Mar	35,921	105,222	865	2,224
2012	Apr	43,777	120,955	1,013	2,519
2012	May	43,468	119,374	1,052	2,541
2012	Jun	35,052	101,065	915	2,193
2012	Jul	35,179	118,294	981	2,710
2012	Aug	35,515	122,458	986	2,787
2012	Sep	35,199	112,731	946	2,801
2012	Oct	35,365	106,819	990	2,692
2012	Nov	40,499	143,853	1,329	3,934
2012	Dec	45,536	176,660	1,681	5,145
2012	Annual	38,343	119,744	1,033	2,801
2013	Jan	44,844	157,229	883	4,205
2013	Feb	46,351	144,066	893	3,862
2013	Mar	48,937	162,958	853	3,740
2013	Apr	57,938	193,366	1,683	4,229
2013	May	59,700	203,521	1,679	4,754
2013	Jun	60,210	229,912	1,984	5,997
2013	Jul	49,674	201,630	1,658	5,300
2013	Aug	44,765	157,748	1,477	3,923
2013	Sep	45,412	136,813	1,408	3,507
2013	Annual	50,870	176,360	1,391	4,391

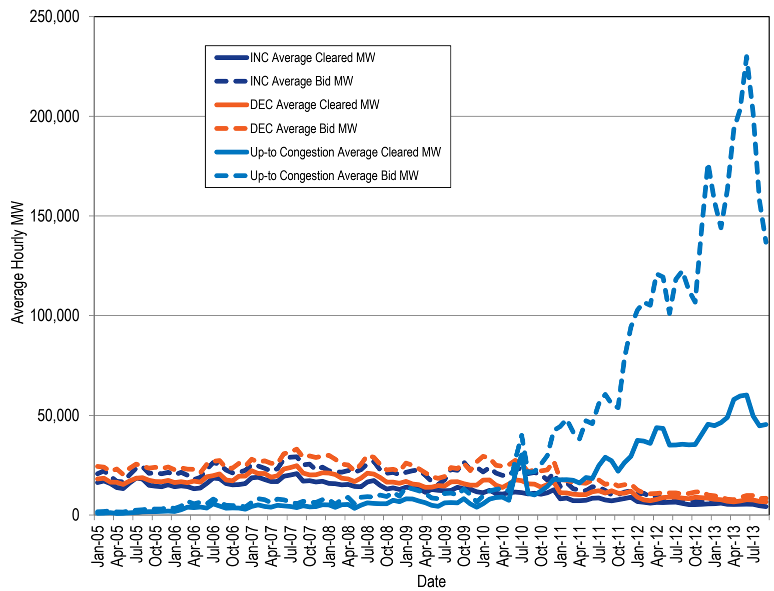
Table 3-54 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.

Table 3-54 Type of day-ahead marginal units: January through September 2013

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.8%	0.1%	91.7%	2.6%	1.8%	0.0%
Feb	3.4%	0.1%	92.9%	1.8%	1.8%	0.0%
Mar	2.5%	0.1%	95.8%	0.8%	0.8%	0.0%
Apr	0.4%	0.0%	98.5%	0.4%	0.6%	0.0%
May	0.6%	0.1%	98.4%	0.5%	0.4%	0.0%
Jun	0.6%	0.0%	97.5%	1.3%	0.7%	0.0%
Jul	0.8%	0.1%	97.0%	1.4%	0.7%	0.0%
Aug	0.4%	0.0%	97.6%	0.9%	1.1%	0.0%
Sep	0.6%	0.0%	96.2%	1.5%	1.6%	0.0%
Annual	1.5%	0.1%	96.2%	1.2%	1.0%	0.0%

Figure 3-24 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 3-24 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through September, 2013



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 3-55 shows, for the first nine months of 2012 and 2013, the total increment offers and decrement bids by whether the parent organization is financial or physical. Table 3-56 shows for the first nine months of 2012 and 2013, the total up-to congestion transactions by the type of parent organization.

The top five companies with cleared up-to congestion transactions are financial and account for 62.4 percent of all the cleared up-to congestion MW in PJM in the first nine months of 2013.

Table 3-55 PJM INC and DEC bids by type of parent organization (MW): January through September of 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	47,082,084	35.8%	26,283,017	26.1%
Physical	84,316,277	64.2%	74,273,099	73.9%
Total	131,398,361	100.0%	100,556,116	100.0%

Table 3-56 PJM up-to congestion transactions by type of parent organization (MW): January through September of 2012 and 2013

	2012 (Jan - Sep)		2013 (Jan - Sep)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	235,531,919	95.2%	308,437,367	94.9%
Physical	11,950,279	4.8%	16,406,890	5.1%
Total	247,482,198	100.0%	324,844,257	100.0%

Table 3-57 shows increment offers and decrement bids bid by top ten locations for the first nine months of 2012 and 2013.

Table 3-57 PJM virtual offers and bids by top ten locations (MW): January through September of 2012 and 2013

2012 (Jan - Sep)					2013 (Jan - Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	22,645,383	25,448,690	48,094,072	WESTERN HUB	HUB	18,258,244	20,361,577	38,619,822
AEP-DAYTON HUB	HUB	3,906,488	4,420,709	8,327,197	N ILLINOIS HUB	HUB	2,021,644	3,654,208	5,675,852
SOUTHIMP	INTERFACE	7,038,188	0	7,038,188	SOUTHIMP	INTERFACE	5,630,343	0	5,630,343
N ILLINOIS HUB	HUB	2,059,281	4,605,627	6,664,908	AEP-DAYTON HUB	HUB	2,616,995	2,688,829	5,305,824
MISO	INTERFACE	248,793	5,303,608	5,552,401	IMO	INTERFACE	4,540,932	48,272	4,589,204
PPL	ZONE	286,342	4,331,684	4,618,026	PPL	ZONE	61,732	3,970,883	4,032,615
PECO	ZONE	858,512	3,219,905	4,078,417	MISO	INTERFACE	339,271	2,691,878	3,031,149
IMO	INTERFACE	2,591,173	45,924	2,637,097	PECO	ZONE	84,716	2,790,652	2,875,368
BGE	ZONE	167,525	1,542,604	1,710,129	BGE	ZONE	26,503	1,524,036	1,550,539
METED	ZONE	133,855	1,063,889	1,197,744	DOMINION HUB	HUB	241,152	1,292,010	1,533,161
Top ten total		39,935,538	49,982,640	89,918,178			33,821,532	39,022,345	72,843,878
PJM total		58,491,377	72,906,984	131,398,361			42,848,449	57,707,667	100,556,116
Top ten total as percent of PJM total		68.3%	68.6%	68.4%			78.9%	67.6%	72.4%

Table 3-58 shows up-to congestion transactions by import bids for the top ten locations for the first nine months of 2012 and 2013.[58]

Table 3-59 shows up-to congestion transactions by export bids for the top ten locations for the first nine months of 2012 and 2013.

Table 3-58 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through September of 2012 and 2013

2012 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	8,832,551
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,265,566
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,958,932
OVEC	INTERFACE	DEOK	ZONE	1,795,528
OVEC	INTERFACE	COOK	EHVAGG	1,664,824
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,658,701
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,598,854
NYIS	INTERFACE	HUDSON BC	AGGREGATE	1,477,807
OVEC	INTERFACE	STUART 1	AGGREGATE	1,456,182
MISO	INTERFACE	COOK	EHVAGG	1,386,981
Top ten total				24,095,925
PJM total				122,824,468
Top ten total as percent of PJM total				19.6%
2013 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
OVEC	INTERFACE	DEOK	ZONE	939,254
OVEC	INTERFACE	STUART 1	AGGREGATE	882,562
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	805,645
NYIS	INTERFACE	HUDSON BC	AGGREGATE	762,162
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	656,470
NORTHWEST	INTERFACE	BYRON 1	AGGREGATE	496,011
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	455,771
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	452,895
OVEC	INTERFACE	SPORN 2	AGGREGATE	447,182
MISO	INTERFACE	112 WILTON	EHVAGG	399,528
Top ten total				6,297,480
PJM total				32,351,220
Top ten total as percent of PJM total				19.5%

Table 3-59 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through September of 2012 and 2013

2012 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	3,403,395
ROCKPORT	EHVAGG	OVEC	INTERFACE	3,140,361
23 COLLINS	EHVAGG	MISO	INTERFACE	3,055,342
STUART 1	AGGREGATE	OVEC	INTERFACE	2,144,288
WESTERN HUB	HUB	MISO	INTERFACE	1,643,318
ROCKPORT	EHVAGG	MISO	INTERFACE	1,572,838
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,554,154
SPORN 3	AGGREGATE	OVEC	INTERFACE	1,472,620
STUART 4	AGGREGATE	OVEC	INTERFACE	1,292,612
SPORN 5	AGGREGATE	OVEC	INTERFACE	1,184,697
Top ten total				20,463,626
PJM total				122,815,948
Top ten total as percent of PJM total				16.7%
2013 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	1,901,810
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,074,478
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	1,055,665
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	949,703
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	875,503
GAVIN	EHVAGG	OVEC	INTERFACE	641,654
ROCKPORT	EHVAGG	OVEC	INTERFACE	571,378
EAST BEND 2	AGGREGATE	OVEC	INTERFACE	556,385
SPORN 3	AGGREGATE	OVEC	INTERFACE	545,195
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	533,133
Top ten total				8,704,904
PJM total				38,431,224
Top ten total as percent of PJM total				22.7%

58 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-60 shows up-to congestion transactions by wheel bids for the top ten locations for the first nine months of 2012 and 2013.

Table 3-60 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through September of 2012 and 2013

2012 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	252,804
NYIS	INTERFACE	IMO	INTERFACE	162,091
SOUTHIMP	INTERFACE	MISO	INTERFACE	147,801
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	120,035
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	112,478
MISO	INTERFACE	NIPSCO	INTERFACE	102,657
NORTHWEST	INTERFACE	MISO	INTERFACE	99,449
OVEC	INTERFACE	IMO	INTERFACE	72,960
MISO	INTERFACE	OVEC	INTERFACE	66,900
SOUTHWEST	INTERFACE	OVEC	INTERFACE	61,943
Top ten total				1,199,119
PJM total				1,841,782
Top ten total as percent of PJM total				65.1%
2013 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	685,232
NORTHWEST	INTERFACE	MISO	INTERFACE	396,607
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	300,204
IMO	INTERFACE	NYIS	INTERFACE	272,426
MISO	INTERFACE	NIPSCO	INTERFACE	259,584
OVEC	INTERFACE	IMO	INTERFACE	109,350
MISO	INTERFACE	SOUTHEXP	INTERFACE	104,052
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	88,280
MISO	INTERFACE	OVEC	INTERFACE	79,810
NORTHWEST	INTERFACE	OVEC	INTERFACE	78,419
Top ten total				2,373,962
PJM total				3,144,557
Top ten total as percent of PJM total				75.5%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up-to congestion transaction.[59] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 7.9 percent of the PJM total internal up-to congestion transactions in the first nine months of 2013.

Table 3-61 shows up-to congestion transactions by internal bids for the top ten locations for the first nine months of 2013.

Table 3-61 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through September of 2013

2013 (Jan - Sep)				
Internal				
Source	Source Type	Sink	Sink Type	MW
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	3,248,461
ATSI GEN HUB	HUB	ATSI	ZONE	3,180,687
MT STORM	EHVAGG	GREENLAND GAP	EHVAGG	3,060,670
FE GEN	AGGREGATE	ATSI	ZONE	1,778,421
AEP-DAYTON HUB	HUB	WESTERN HUB	HUB	1,690,443
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	1,519,249
WYOMING	EHVAGG	BROADFORD	EHVAGG	1,417,822
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,371,354
WHITPAIN	EHVAGG	ELROY	EHVAGG	1,313,998
NAPERVILLE	AGGREGATE	WINNETKA	AGGREGATE	1,189,073
Top ten total				19,770,178
PJM total				250,917,257
Top ten total as percent of PJM total				7.9%

Table 3-62 shows the number of source-sink pairs that were offered and cleared monthly in 2012 and the first nine months of 2013. The increase in average offered and cleared source-sink pairs in November and December of 2012 and the first nine months of 2013 illustrates that PJM's modification of the rules governing the location of up-to congestion transactions bids resulted in a significant increase in the number of offered and cleared up-to congestion transactions. The increase in source-sink pairs available for up-to congestion transactions has also led to increased dispersion in cleared up-to congestion transaction internal bids by location.

59 For more information, see the *2012 State of the Market Report for PJM,* Volume II, Section 8, "Interchange Transactions," Up-to Congestion.

Table 3-62 Number of PJM offered and cleared source and sink pairs: January 2012 through September of 2013

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2012	Jan	1,771	2,182	1,126	1,568
2012	Feb	1,816	2,198	1,156	1,414
2012	Mar	1,746	2,004	1,128	1,353
2012	Apr	1,753	2,274	1,117	1,507
2012	May	1,866	2,257	1,257	1,491
2012	Jun	2,145	2,581	1,425	1,897
2012	Jul	2,168	2,800	1,578	2,078
2012	Aug	2,541	3,043	1,824	2,280
2012	Sep	2,140	3,032	1,518	2,411
2012	Oct	2,344	3,888	1,569	2,625
2012	Nov	4,102	8,142	2,829	5,811
2012	Dec	9,424	13,009	5,025	8,071
2012	Jan-Oct	2,031	3,888	1,371	2,625
2012	Nov-Dec	6,806	13,009	3,945	8,071
2012	Annual	2,818	3,951	1,796	2,709
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Apr	6,426	9,094	3,464	4,827
2013	May	5,729	7,914	3,350	4,495
2013	Jun	6,014	8,437	3,490	4,775
2013	Jul	5,955	9,006	3,242	4,938
2013	Aug	6,215	9,751	3,642	5,117
2013	Sep	3,496	4,222	2,510	3,082
2013	Annual	5,574	8,204	3,179	4,496

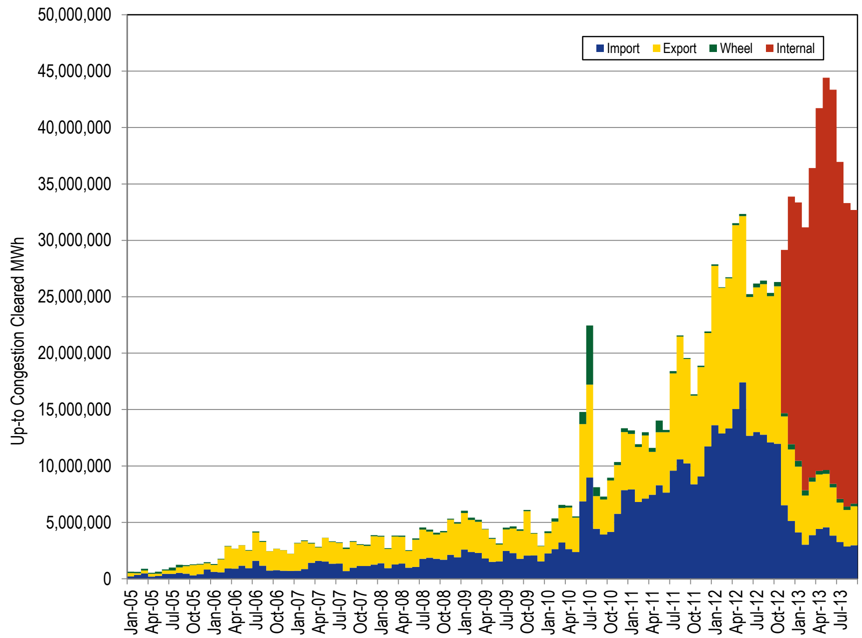
Table 3-63 PJM cleared up-to congestion transactions by type (MW): January through September of 2012 and 2013

	2012 (Jan - Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	24,095,925	20,463,626	1,199,119	NA	31,289,254
PJM total (MW)	122,824,468	122,815,948	1,841,782	NA	247,482,198
Top ten total as percent of PJM total	19.6%	16.7%	65.1%	NA	12.6%
PJM total as percent of all up-to congestion transactions	49.6%	49.6%	0.7%	NA	100.0%
	2013 (Jan - Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	6,297,480	8,704,904	2,373,962	19,770,178	20,482,915
PJM total (MW)	32,351,220	38,431,224	3,144,557	250,917,257	324,844,257
Top ten total as percent of PJM total	19.5%	22.7%	75.5%	7.9%	6.3%
PJM total as percent of all up-to congestion transactions	10.0%	11.8%	1.0%	77.2%	100.0%

Table 3-63 and Figure 3-25 show total cleared up-to congestion transactions by type for the first nine months of 2012 and 2013. Internal up-to congestion transactions in the first nine months of 2013 were 77.2 percent of all up-to congestion transactions for the first nine months of 2013.

Figure 3-25 shows the initial increase and continued rise of internal up-to congestion transactions in November and December of 2012 and the first nine months of 2013, following the November 1, 2012, rule change permitting such transactions.

Figure 3-25 PJM cleared up-to congestion transactions by type (MW): January 2005 through September of 2013



Price Convergence

The introduction of the PJM Day-Ahead Energy Market created the possibility that competition, exercised through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Convergence is not the goal of virtual trading but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Market. Price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that Day-Ahead and Real-Time prices are equal at individual buses or aggregates is not a realistic expectation. PJM markets do not provide a mechanism that could result in convergence within any individual day as there is at least a one-day lag after any change in system conditions. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. Substantial virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 3-27).

Table 3-64 shows that the difference between average day-ahead and real-time prices was $0.29 per MWh in the first nine months of 2012 and -$0.20 per MWh in the first nine months of 2013. The difference between average on-peak day-ahead and real-time prices was $1.34 per MWh in the first nine months of 2012 and $0.16 per MWh in the first nine months of 2013.

Table 3-64 Day-ahead and real-time average LMP (Dollars per MWh): January through September of 2012 and 2013[60]

	2012 (Jan - Sep)				2013 (Jan - Sep)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$32.16	$32.45	$0.29	0.9%	$37.50	$37.30	($0.20)	(0.5%)
Median	$30.10	$28.78	($1.32)	(4.6%)	$34.70	$32.44	($2.26)	(7.0%)
Standard deviation	$14.54	$21.94	$7.40	33.7%	$16.96	$22.84	$5.88	25.7%
Peak average	$38.16	$39.50	$1.34	3.4%	$44.58	$44.74	$0.16	0.4%
Peak median	$33.74	$32.19	($1.55)	(4.8%)	$40.32	$37.41	($2.91)	(7.8%)
Peak standard deviation	$17.76	$27.37	$9.60	35.1%	$21.37	$28.77	$7.40	25.7%
Off peak average	$26.95	$26.33	($0.62)	(2.4%)	$31.31	$30.80	($0.51)	(1.7%)
Off peak median	$25.95	$25.20	($0.74)	(2.9%)	$30.07	$28.44	($1.63)	(5.7%)
Off peak standard deviation	$7.92	$12.98	$5.06	39.0%	$7.58	$12.77	$5.19	40.7%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from conditions in the Real-Time Energy Market that are difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 3-65 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first nine months of each year of the 13-year period 2001 to 2013.

Table 3-65 Day-ahead and real-time average LMP (Dollars per MWh): January through September of 2001 through 2013

(Jan - Sep)	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%
2013	$37.50	$37.30	($0.20)	(0.5%)

60 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-66 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first nine months of the years 2007 through 2013.

Table 3-66 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through September of 2007 through 2013

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	5	0.08%	4	0.06%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%	6	0.17%	5	0.14%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%	17	0.43%	9	0.27%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%	4,112	62.97%	4,338	66.49%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%	2,343	98.60%	2,112	98.73%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%	61	99.53%	58	99.62%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%	14	99.74%	12	99.80%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%	10	99.89%	10	99.95%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%	4	99.95%	1	99.97%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%	1	99.97%	2	100.00%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%	2	100.00%	0	100.00%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%

Figure 3-26 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first nine months of 2013.

Figure 3-26 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through September of 2013

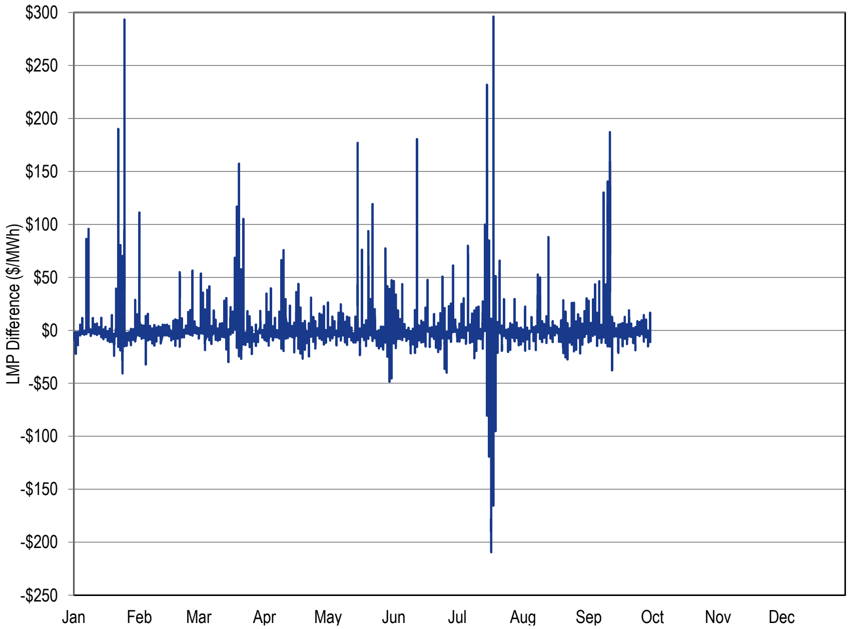


Figure 3-27 shows the monthly average differences between the day-ahead and real-time LMP in the first nine months of 2013.

Figure 3-27 Monthly average of real-time minus day-ahead LMP: January through September of 2013

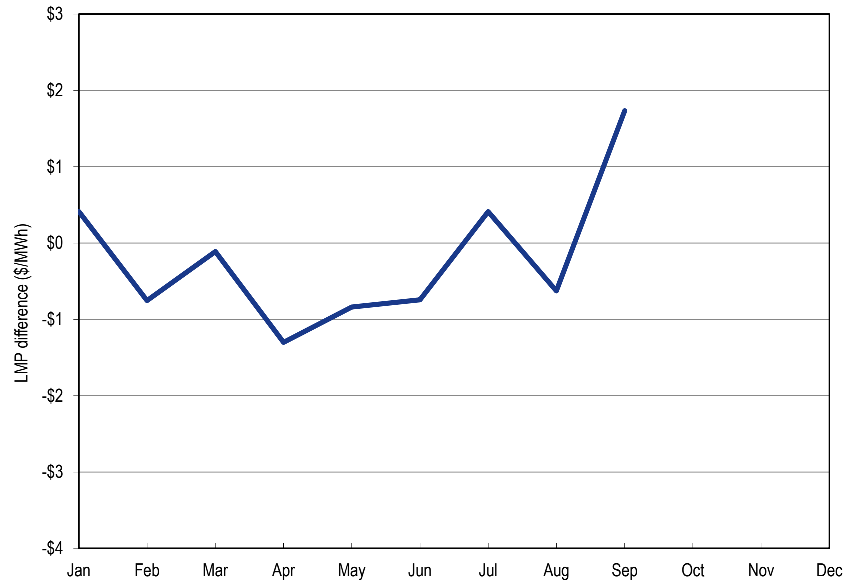
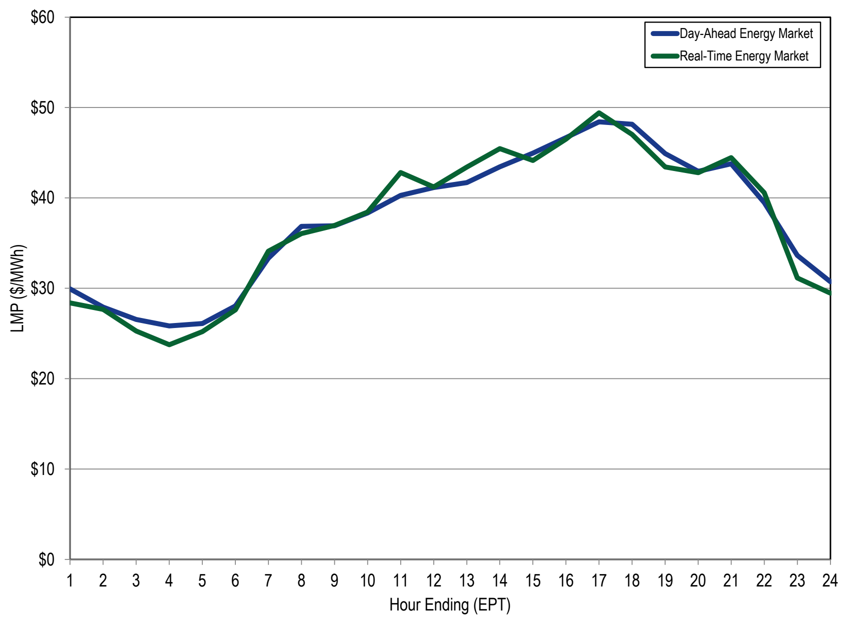


Figure 3-28 shows day-ahead and real-time LMP on an average hourly basis for the first nine months of 2013.

Figure 3-28 PJM system hourly average LMP: January through September of 2013



Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a non-affiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-67 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2012 and 2013 based on parent company. For the first nine months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 24.1 percent by spot market purchase and 65.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot supply increased by 0.9 percentage points and reliance on self-supply decreased by 2.3 percentage points.

Table 3-67 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	8.9%	22.0%	69.1%	10.4%	22.3%	67.3%	1.5%	0.2%	(1.8%)
Feb	8.8%	21.2%	70.0%	10.5%	22.0%	67.5%	1.7%	0.8%	(2.4%)
Mar	9.4%	23.6%	67.1%	10.4%	24.2%	65.4%	1.1%	0.6%	(1.6%)
Apr	9.4%	23.8%	66.8%	10.7%	24.2%	65.1%	1.3%	0.4%	(1.6%)
May	8.6%	23.5%	67.9%	10.9%	25.4%	63.6%	2.4%	1.9%	(4.3%)
Jun	8.7%	22.3%	69.0%	10.7%	25.0%	64.3%	2.0%	2.7%	(4.8%)
Jul	8.0%	22.7%	69.3%	10.2%	25.2%	64.7%	2.2%	2.5%	(4.6%)
Aug	8.5%	23.6%	67.9%	10.2%	24.5%	65.3%	1.7%	0.8%	(2.6%)
Sep	9.1%	24.4%	66.5%	10.1%	24.2%	65.7%	1.1%	(0.2%)	(0.9%)
Oct	9.6%	25.5%	64.9%						
Nov	9.9%	23.9%	66.3%						
Dec	10.2%	22.6%	67.3%						
Annual	9.0%	23.2%	67.8%	10.5%	24.1%	65.4%	1.4%	0.9%	(2.3%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as generation in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead load (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 3-68 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2012 and 2013, based on parent companies. For the first nine months of 2013, 7.5 percent of day-ahead load was supplied by bilateral contracts, 23.4 percent by spot market purchases, and 69.1 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply increased by 1.1 percentage points, and reliance on self-supply decreased by 1.9 percentage points.

Table 3-68 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	6.6%	21.4%	72.0%	6.8%	22.1%	71.1%	0.2%	0.7%	(0.9%)
Feb	6.7%	20.0%	73.3%	7.0%	22.1%	71.0%	0.3%	2.1%	(2.3%)
Mar	6.7%	22.8%	70.5%	7.0%	23.6%	69.4%	0.3%	0.8%	(1.1%)
Apr	6.7%	22.8%	70.6%	7.1%	23.1%	69.8%	0.5%	0.3%	(0.8%)
May	6.6%	22.7%	70.7%	7.8%	23.5%	68.7%	1.2%	0.8%	(2.0%)
Jun	7.7%	20.7%	71.6%	8.2%	23.8%	68.0%	0.5%	3.1%	(3.5%)
Jul	5.9%	22.0%	72.0%	8.0%	24.1%	67.9%	2.0%	2.1%	(4.1%)
Aug	6.4%	22.5%	71.0%	8.1%	23.9%	68.0%	1.7%	1.4%	(3.1%)
Sep	6.5%	23.9%	69.6%	7.8%	23.9%	68.3%	1.3%	(0.0%)	(1.3%)
Oct	6.6%	25.2%	68.2%						
Nov	6.9%	22.7%	70.5%						
Dec	7.0%	21.2%	71.8%						
Annual	6.7%	22.3%	71.0%	7.5%	23.4%	69.1%	0.9%	1.1%	(1.9%)

Operating Reserve

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss.[1] Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

Overview

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges increased by 33.7 percent in the first nine months of 2013 compared to the first nine months of 2012, to a total of $652.9 million.

  Day-ahead operating reserve charges were 11.3 percent, balancing operating reserve charges were 48.3 percent, reactive services charges were 29.8 percent, synchronous condensing charges were 0.06 percent and black start services charges were 10.6 percent of total operating reserve charges in 2013.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.086 per MWh. The day-ahead operating reserve rate including unallocated congestion charges averaged $0.118 per MWh. The balancing operating reserve reliability rates averaged $0.052, $0.031 and $0.004 per MWh for the RTO, Eastern and Western Regions. The balancing operating reserve deviation rates averaged $0.886, $2.193 and $0.118 per MWh for the RTO, Eastern and Western Regions. The lost opportunity cost rate averaged $0.861 per MWh and the canceled resources rate averaged $0.001 per MWh.

- **Reactive Service Rates.** The DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $1.952, $1.557 and $0.631 per MWh. The reactive transfer interface support rate averaged $0.141 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 46.7 percent of all day-ahead generator credits and 52.6 percent of all balancing generator credits. Combustion turbines and diesels received 73.7 percent of the lost opportunity cost credits. Combined cycles and coal units received 91.4 percent of all reactive services credits.

- **Economic and Noneconomic Generation.** In the first nine months of 2013, 81.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.1 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In the first nine months of 2013, 81.6 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 6.1 percent by transactions at hubs and aggregates and 12.3 percent by transactions at interfaces.

- Generators in the Eastern Region paid 15.0 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 75.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 13.9 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 24.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- Generators paid 9.8 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.96 percent of all credits.

1 See the *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Description of Operating Reserves" pp. 99-103 for a full description of how operating reserve credits and charges are calculated.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 34.5 percent of all credits. The top 10 organizations received 86.1 percent of all credits. Concentration indexes for the three largest operating reserve categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5343, balancing operating reserves HHI was 3927 and lost opportunity cost HHI was 4699.
- **Day-Ahead Unit Commitment for Reliability:** In the first nine months of 2013, 4.7 percent of the total day-ahead generation was scheduled as must run by PJM, of which 65.4 percent was made whole.
- **Lost Opportunity Cost Credits:** In the first nine months of 2013, lost opportunity cost credits decreased by $66.0 million compared to the first nine months of 2012. In the first nine months of 2013, the top three control zones receiving lost opportunity cost credits, AEP, ComEd and Dominion accounted for 60.7 percent of all lost opportunity cost credits, 53.6 percent of the credits for day-ahead generation from pool-scheduled combustion turbines and diesels, 57.6 percent of the credits for day-ahead generation not called in real time by PJM from those unit types and 53.9 percent of the credits day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Lost Opportunity Cost Calculation:** In the first nine months of 2013, lost opportunity cost credits would have been reduced by an additional $21.3 million, or 26.1 percent, if all changes proposed by the MMU had been implemented.
- **Black Start Service Units:** Certain units located in the AEP zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In the first nine months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $68.7 million.
- **Con Edison – PSEG Wheeling Contracts Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing operating reserves credits.
- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to operating reserve charges proposed by the MMU on operating reserve charge rates would be significant. For example, in the first nine months of 2013, the average rate paid by a DEC in the Eastern Region would have been $0.218 per MWh, which is $3.564 per MWh, 94.2 percent, less than the actual average rate paid.

Recommendations

- The MMU recommends that the impact of physical constraints of all types be reflected in market prices to the maximum extent possible, reducing the necessity for out of market operating reserve payments and improving the efficiency of market prices.
- The MMU recommends the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.
- The MMU recommends four modifications to the energy lost opportunity cost calculations.
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and

diesels scheduled in the Day-Ahead Energy Market but not called in real time.

— The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.

- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with operating reserve credits calculation.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by location and the detailed reasons for the level of operating reserve payments by location in the PJM region.

Conclusion

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters, the details of the rules which define payments and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. But these costs are collected as operating reserves rather than reflected in price as a result of the rules governing the determination of LMP in situations where something other than a simple thermal transmission constraint affects unit dispatch.

PJM has improved its oversight of operating reserves and continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels. However, given the impact of operating reserve charges on market participants, particularly virtual market participants, the MMU recommends that PJM take another step towards more precise definition and clearly identify and classify all reasons for incurring operating reserve charges in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The MMU recommends that the goal should be to have dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommended and supports PJM in the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.[2] For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.

Overall, the MMU recommends that the goal be to minimize the total level of operating reserve credits paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The goal should be to minimize the total incurred operating reserve charges and to increase the transactions over which those charges are spread in order to reduce the impact of operating reserve charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with operating reserve charges and to reduce the impact of operating reserve charges on decisions about how and when to participate in PJM markets.

Credits and Charges Categories

Operating reserves include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

2 PJM presented a problem statement at the Markets and Reliability Committee (MRC) to perform a holistic review of operating reserves. See "Item 10 – Operating Reserves Problem Statement," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130425/20130425-item-10-operating-reserves-problem-statement.ashx> (Accessed April 26, 2013).

Table 4-1 Day-ahead and balancing operating reserve credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:	
	Day-Ahead				
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Balancing				
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Resources Providing Quick Start Reserve	Balancing Operating Reserve Generator				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-2 Reactive services, synchronous condensing and black start services credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge Reactive Services Local Constraint	Zonal Real-Time Load Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone and Non-zone Peak Transmission Use

Operating Reserve Results

Operating Reserve Charges

Table 4-3 shows total operating reserve charges for the first nine months of 2012 and 2013.[3] Total operating reserve charges increased by 33.7 percent in the first nine months of 2013 compared to the first nine months of 2012, to a total of $652.9 million.

Table 4-3 Total operating reserve charges: January through September 2012 and 2013

	Jan - Sep 2012	Jan - Sep 2013	Change	Percentage Change
Total Operating Reserve Charges	$488,178,103	$652,904,574	$164,726,471	33.7%
Operating Reserve as a Percent of Total PJM Billing	2.2%	2.6%	0.4%	17.6%

Total operating reserve charges in the first nine months of 2013 were $652.9 million, up from the total of $488.2 million in the first nine months of 2012. Table 4-4 compares monthly operating reserve charges by category for 2012 and 2013. The increase of 33.7 percent in the first nine months of 2013 is comprised of a 13.7 percent decrease in day-ahead operating reserve charges, an 10.7 percent decrease in balancing operating reserve charges, a 294.0 percent increase in reactive services charges, a 453.1 percent increase in synchronous condensing charges and $68.9 million of black start services charges. Black start services operating reserve charges accounted for 10.6 percent of all operating reserve charges.

Table 4-4 Monthly operating reserve charges: 2012 and 2013

	2012						2013					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$8,311,574	$27,341,331	$2,934,337	$27,037	$0	$38,614,279	$11,161,579	$79,219,217	$23,604,234	$1,873	$8,453,397	$122,440,301
Feb	$5,858,308	$24,877,526	$13,108,017	$18,592	$0	$43,862,444	$5,126,444	$66,886,126	$17,624,984	$0	$6,988,632	$96,626,185
Mar	$3,852,873	$29,758,387	$6,731,994	$1,648	$0	$40,344,903	$6,900,582	$17,493,458	$14,350,138	$0	$6,768,618	$45,512,796
Apr	$2,967,302	$34,172,651	$4,521,280	$0	$0	$41,661,233	$5,712,618	$23,089,668	$13,670,581	$0	$9,242,815	$51,715,682
May	$7,956,965	$43,761,595	$5,392,428	$0	$0	$57,110,987	$10,437,734	$22,560,252	$17,214,142	$959	$8,667,665	$58,880,751
Jun	$6,973,548	$46,011,835	$5,133,009	$0	$0	$58,118,391	$9,350,026	$17,900,744	$22,055,239	$0	$7,954,457	$57,260,466
Jul	$11,773,179	$66,931,225	$2,960,922	$0	$0	$81,665,326	$8,309,568	$44,202,434	$20,305,968	$393,413	$5,858,221	$79,069,604
Aug	$8,692,702	$47,785,303	$4,112,186	$0	$0	$60,590,191	$4,159,471	$14,124,338	$30,738,131	$0	$7,584,998	$56,606,938
Sep	$28,877,736	$32,849,356	$4,458,891	$24,366	$0	$66,210,349	$12,452,502	$30,079,327	$34,875,468	$0	$7,384,554	$84,791,851
Oct	$23,235,166	$26,884,798	$1,253,642	$38,762	$0	$51,412,367						
Nov	$18,077,440	$24,488,338	$120,820	$0	$0	$42,686,598						
Dec	$7,868,340	$27,902,608	$25,282,650	$37,845	$8,384,651	$69,476,094						
Total (Jan - Sep)	$85,264,187	$353,489,210	$49,353,063	$71,643	$0	$488,178,103	$73,610,524	$315,555,563	$194,438,886	$396,245	$68,903,357	$652,904,574
Share (Jan - Sep)	17.5%	72.4%	10.1%	0.0%	0.0%	100.0%	11.3%	48.3%	29.8%	0.1%	10.6%	100.0%
Total	$134,445,132	$432,764,953	$76,010,175	$148,250	$8,384,651	$651,753,162						
Share	20.6%	66.4%	11.7%	0.0%	1.3%	100.0%						

3 Table 4-3 includes all categories of charges as defined in Table 4-1 and Table 4-2 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The billing data reflected in this report were current on July 9, 2013.

Table 4-5 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges attributable to generators and import transactions, day-ahead operating reserve charges for load response and day-ahead operating reserve charges attributable to unallocated congestion charges.[4,5,6] Day-ahead operating reserve charges decreased 13.7 percent or $11.7 million in the first nine months of 2013 compared to the first nine months of 2012. Day-ahead operating reserve charges attributable to generators and imports decreased by $31.7 million in the first nine months of 2013 compared to the first nine months of 2012, but unallocated congestion charges increased from zero in the first nine months of 2012 to $20.0 million in the first nine months of 2013. These charges are paid by day-ahead demand, day-ahead exports and decrement bids.

Table 4-6 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (attributable to generators), balancing operating reserve deviation charges (attributable to generators and import transactions), balancing operating reserve charges for load response and balancing local constraint charges. In the first nine months of 2013, balancing operating reserve deviation charges accounted for 86.8 percent of all balancing operating reserve charges, 8.7 percentage points higher than in the first nine months of 2012.

Table 4-5 Day-ahead operating reserve charges: January through September 2012 and 2013

Type	Jan - Sep 2012	Jan - Sep 2013	Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Day-Ahead Operating Reserve Charges	$85,264,108	$53,563,633	($31,700,475)	100.0%	72.8%
Day-Ahead Operating Reserve Charges for Load Response	$78	$3,561	$3,483	0.0%	0.0%
Unallocated Congestion Charges	$0	$20,043,330	$20,043,330	0.0%	27.2%
Total	$85,264,187	$73,610,524	($11,653,663)	100.0%	100.0%

Table 4-6 Balancing operating reserve charges: January through September 2012 and 2013

Type	Jan - Sep 2012	Jan - Sep 2013	Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Balancing Operating Reserve Reliability Charges	$69,634,249	$41,394,880	($28,239,369)	19.7%	13.1%
Balancing Operating Reserve Deviation Charges	$276,011,360	$273,902,539	($2,108,821)	78.1%	86.8%
Balancing Operating Reserve Charges for Load Response	$312,874	$182,506	($130,368)	0.1%	0.1%
Balancing Local Constraint Charges	$7,530,727	$75,638	($7,455,089)	2.1%	0.0%
Total	$353,489,210	$315,555,563	($37,933,647)	100.0%	100.0%

4 Attributable means that these charges are the result of credits paid to the identified resources.
5 See OATT Attachment K - Appendix § 3.2.3 (c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves ten times, totaling $26.9 million, of which 74.6 percent was charged in the first nine months of 2013.
6 See Section 12, "Financial Transmission Rights and Auction Revenue Rights" at "Unallocated Congestion Charges" for an explanation of the source of these charges.

Table 4-7 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges consist of charges attributable to make whole payments to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In the first nine months of 2013, 70.3 percent of all balancing operating reserve deviation charges were attributable to make whole payments to generators and import transactions, an increase of 24.9 percentage points compared to the share in the first nine months of 2012.

Table 4-7 Balancing operating reserve deviation charges: January through September 2012 and 2013

Charge attributable to	Jan - Sep 2012	Jan - Sep 2013	Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Make Whole Payments to Generators and Imports	$125,373,701	$192,650,537	$67,276,836	45.4%	70.3%
Energy Lost Opportunity Cost	$147,319,461	$81,117,893	($66,201,568)	53.4%	29.6%
Canceled Resources	$3,318,199	$134,109	($3,184,090)	1.2%	0.0%
Total	$276,011,360	$273,902,539	($2,108,821)	100.0%	100.0%

Table 4-8 shows reactive services, synchronous condensing and black start services charges. Black start services charges were introduced in December 2012.

Table 4-8 Additional operating reserve charges: January through September 2012 and 2013

Type	Jan - Sep 2012	Jan - Sep 2013	Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Reactive Services Charges	$49,353,063	$194,438,886	$145,085,823	99.9%	73.7%
Synchronous Condensing Charges	$71,643	$396,245	$324,602	0.1%	0.2%
Black Start Services Charges	$0	$68,903,357	$68,903,357	0.0%	26.1%
Total	$49,424,706	$263,738,487	$214,313,781	100.0%	100.0%

Table 4-9 and Table 4-10 show the amount and percentages of regional balancing charges allocation for the first nine months of 2012 and 2013. Regional balancing operating reserve charges consist of the balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations in the RTO region. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints and resources providing quick start reserve.

In the first nine months of 2013, regional balancing operating reserve charges decreased by $30.3 million compared to the first nine months of 2012. Balancing operating reserve reliability charges decreased by $28.2 million or 40.6 percent and balancing operating reserve deviation charges decreased by $2.1 million or 0.8 percent. Total balancing operating reserve deviation charges decreased in the first nine months of 2013 compared to the first nine months of 2012, but in the first nine months of 2013, deviation charges in the Eastern Region increased by $89.3 million compared to the first nine months of 2012, as a result of payments to units providing relief to transmission constraints in north/central New Jersey and units providing support to the Con Edison – PSEG wheeling contracts.[7,8] The remaining two deviation categories decreased by $91.4 million.

7 See "Selected MMU Market Issues," MMU Presentation to the Members Committee (February 25, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mc/20130225-webinar/20130225-item-08-imm-flowchart.ashx>.

8 See "Winter 2012-2013: Balancing Operating Reserve Rates," PJM Presentation at the Market Implementation Committee (MIC) (March 6, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-10-winter-2012-2013-bor-rates.ashx>.

Table 4-9 Regional balancing charges allocation: January through September 2012

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$13,502,197	3.9%	$7,743,241	2.2%	$45,958,032	13.3%	$67,203,469	19.4%
	Real-Time Exports	$391,518	0.1%	$163,838	0.0%	$1,875,423	0.5%	$2,430,780	0.7%
	Total	$13,893,715	4.0%	$7,907,079	2.3%	$47,833,455	13.8%	$69,634,249	20.1%
Deviation Charges	Demand	$153,237,456	44.3%	$9,169,952	2.7%	$3,801,990	1.1%	$166,209,398	48.1%
	Supply	$45,008,686	13.0%	$2,962,187	0.9%	$898,808	0.3%	$48,869,681	14.1%
	Generator	$56,717,131	16.4%	$2,549,568	0.7%	$1,665,582	0.5%	$60,932,281	17.6%
	Total	$254,963,272	73.8%	$14,681,707	4.2%	$6,366,381	1.8%	$276,011,360	79.9%
Total Regional Balancing Charges		$268,856,987	77.8%	$22,588,786	6.5%	$54,199,836	15.7%	$345,645,609	100%

Table 4-10 Regional balancing charges allocation: January through September 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$30,442,807	9.7%	$8,760,222	2.8%	$1,240,266	0.4%	$40,443,294	12.8%
	Real-Time Exports	$692,053	0.2%	$228,044	0.1%	$31,489	0.0%	$951,586	0.3%
	Total	$31,134,859	9.9%	$8,988,266	2.9%	$1,271,755	0.4%	$41,394,880	13.1%
Deviation Charges	Demand	$97,950,152	31.1%	$64,160,776	20.3%	$2,942,771	0.9%	$165,053,699	52.3%
	Supply	$26,694,910	8.5%	$17,299,379	5.5%	$833,154	0.3%	$44,827,443	14.2%
	Generator	$40,005,197	12.7%	$22,509,431	7.1%	$1,506,770	0.5%	$64,021,397	20.3%
	Total	$164,650,258	52.2%	$103,969,585	33.0%	$5,282,696	1.7%	$273,902,539	86.9%
Total Regional Balancing Charges		$195,785,117	62.1%	$112,957,851	35.8%	$6,554,450	2.1%	$315,297,419	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. See Table 4-1 for how these charges are allocated.[9]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2012 and the first nine months of 2013. The average rate in the first nine months of 2013 was $0.086 per MWh, $0.049 per MWh lower than the average in the first nine months of 2012. The highest rate occurred on July 16, when the rate reached $0.646 per MWh, 25.9 percent lower than the $0.871 per MWh reached during the first nine months of 2012, on September 20. Figure 4-1 also shows the daily day-ahead operating reserve rates including the congestion charges allocated to day-ahead operating reserves. The average rate in the first nine months of 2013, including unallocated congestion charges, was $0.118 per MWh, 37.4 percent higher than the day-ahead operating reserve rate without unallocated congestion charges.

The increase in the day-ahead operating reserve rate on July 16 was in large part the result of scheduling peaking resources which were noneconomic or economic for less than 25 percent of their scheduled run time. On July 16, 83 units received day-ahead operating reserve credits, forty nine were noneconomic for their entire scheduled run time and six were economic for 25 percent or less of their scheduled run time, the highest number of units scheduled noneconomic in day ahead in 2013. On July 16, fifty six units that were made whole though day-ahead operating reserves also provided day-ahead scheduling reserves for which they received additional revenue; thirty four of these units received enough net revenues from day-ahead scheduling reserves to cover their total offer, which would have resulted in zero day-ahead operating reserve credits if the revenues from day-ahead scheduling reserves could be used as an offset in the day-ahead operating reserve credit calculation.[10] The day-ahead operating reserve rate for July 16 would have been $0.244 per MWh or 62.2 percent lower if the offset had been credited. Similar circumstances occurred on July 17, 18, 19 and September 11.

9 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost rates and the canceled resources rate to the deviation rate for the RTO region since these three charges are allocated following the same rules.

10 Net revenues from day-ahead scheduling reserves are used as offsets in the balancing operating reserve calculation.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2012 and 2013[11]

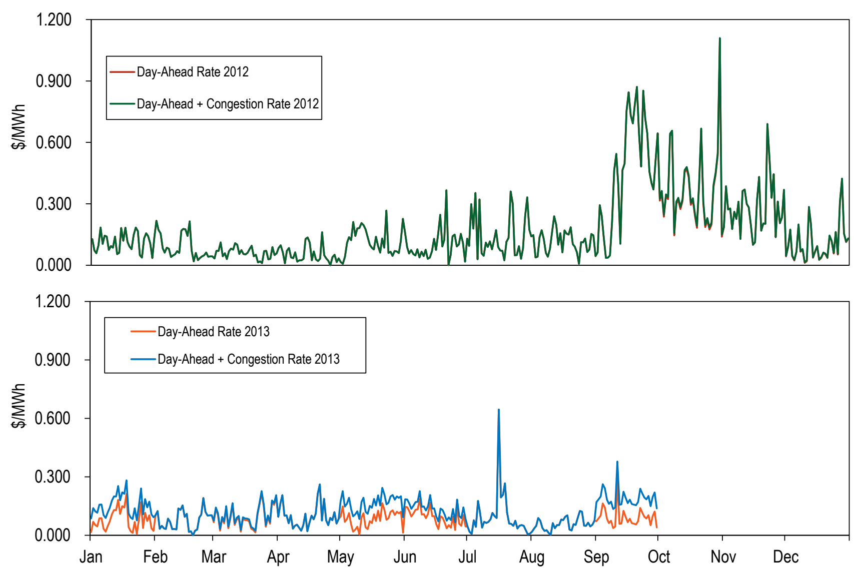


Figure 4-2 shows the RTO and the regional reliability rates for 2012 and the first nine months of 2013. The average daily RTO reliability rate was $0.052 per MWh. The highest RTO reliability rate of the first nine months of 2013 occurred on January 23, when the rate reached $0.802 per MWh. The average daily Eastern Region reliability rate was $0.031 per MWh. The highest Eastern Region reliability rate in the first nine months of 2013 also occurred on January 23, when the rate reached $2.887 per MWh.

The spikes in both rates were the result of a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. The transmission constraints were the result of issues with the 500 kV system which resulted in overloads on the 230 kV system. The issues on the 500 kV system were a combination of unplanned outages and unforeseen outages resulting from damage due to Hurricane Sandy. Cold weather in the region resulted in an increase in the Transco Zone 6 NY natural gas price index in January and February 2013 compared to previous months and compared to January and February 2012. The units committed to provide relief for the transmission constraints only set the LMP during short periods of time in comparison to their minimum run times, which increased the costs of operating reserves during periods when the units continue operating out of merit as a result of their operating parameters.[12]

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2012 and 2013

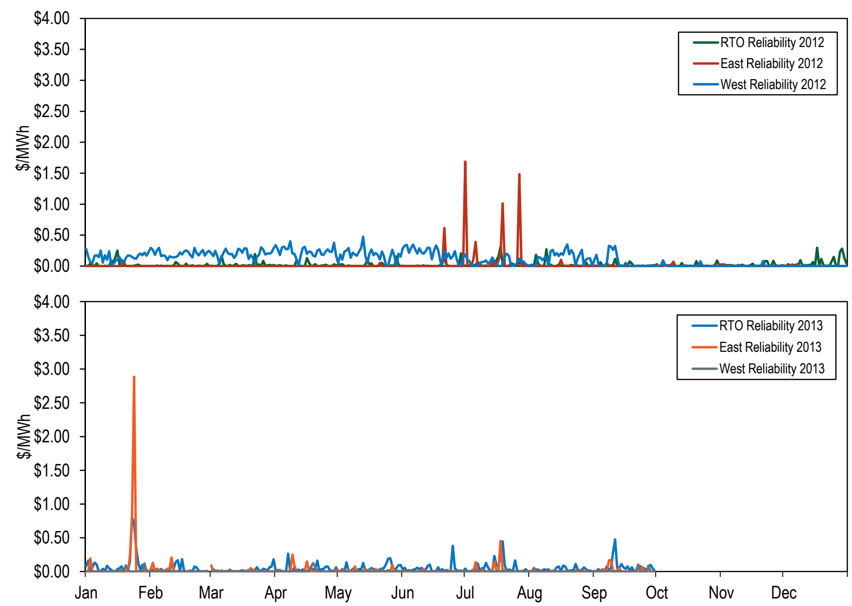


Figure 4-3 shows the RTO and regional deviation rates for 2012 and the first nine months of 2013. The average daily RTO deviation rate was $0.886 per MWh. The highest daily rate in the first nine months of 2013 occurred on January 23, when the RTO deviation rate reached $10.227 per MWh. Between

11 On September 13, 2012, PJM increased the amount of generation scheduled in the Day-Ahead Energy Market for reliability purposes. This change shifted the allocation of certain operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market. See *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

12 The relevant parameters are minimum run time, minimum down time, maximum daily starts and maximum weekly starts.

January 1 and February 21, 2013, the Eastern Region deviation rate averaged $10.045 per MWh, reaching its highest rate on February 9, when it reached $32.876 per MWh. Prior to the 2012 – 2013 winter, the highest daily Eastern Region deviation rate had been $5.739 per MWh. The spikes in the Eastern deviation rate in early January and from mid-January until the end of February were caused by the same issues that caused the RTO and Eastern reliability rates to spike on January 25, a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area.

Current balancing operating reserve rules allocate the costs of operating reserves in real time for reliability or deviations according to when the units are committed (before or during the operating day) and the number of intervals the units were operating noneconomic (more or less than four intervals).[13] The spike in the RTO deviation rate on September 11 was mainly a result of the commitment in real time of combustion turbines that did not clear the Day-Ahead Energy Market and did not recover their total offer through energy and ancillary services revenues. This commitment was triggered by the issuance of a maximum generation action on that day.

13 See the *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Balancing Operating Reserve Cost Allocation" p.101 for a more detailed description of how the cost of balancing operating reserves are allocated.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2012 and 2013

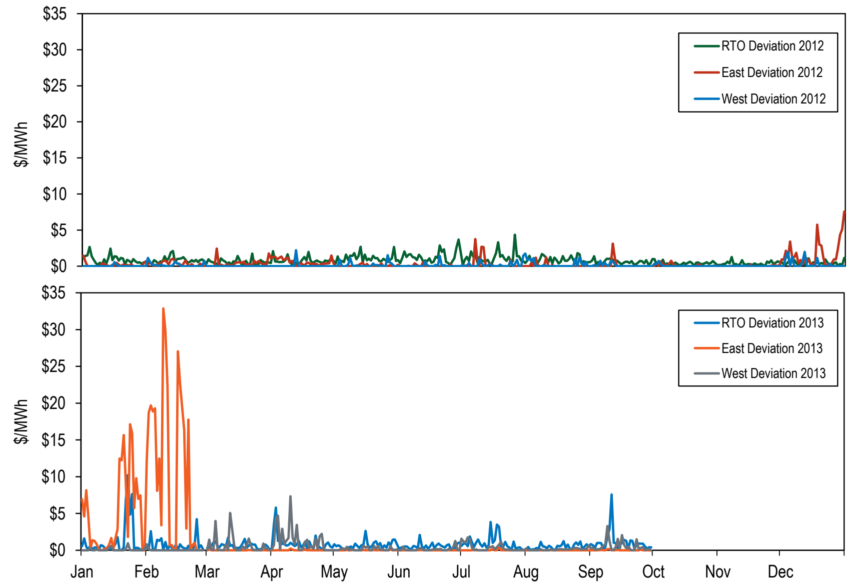


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2012 and the first nine months of 2013. The lost opportunity rate averaged $0.861 per MWh. The highest lost opportunity cost rate occurred on September 11, when it reached $8.370 per MWh.

The LOC rate has shown smaller spikes in the first nine months of 2013 compared to the first nine months of 2012. In the first nine months of 2013 the top ten LOC daily rates averaged $5.001 per MWh, $3.078 per MWh less than the average of the top 10 LOC rates in the first nine months of 2012. The top LOC rates in the first nine months of 2013 occurred between July 16 and July 18 and between September 10 and 11. The main reasons for these spikes continue to be combustion turbines and diesels scheduled in day ahead and not called in real time. Another reason was the need to reduce the output of steam units due to transmission line limits. On September 11, the manual dispatch of a small number of units in the ATSI control zone was responsible for 54.7 percent of the LOC rate, the units were manually dispatched down because of a constraint within ATSI during hours when the ATSI interface was binding and DR was setting ATSI prices at $1,800 per MWh.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2012 and 2013

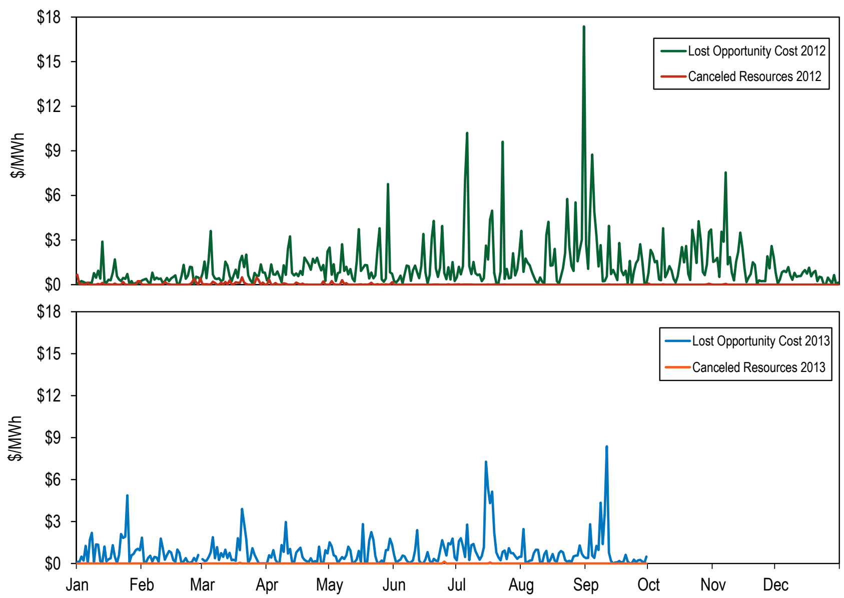


Table 4-11 shows the average rates for each region in each category for the first nine months of 2012 and 2013.

Table 4-11 Operating reserve rates ($/MWh): January through September 2012 and 2013

Rate	Jan - Sep 2012 ($/MWh)	Jan - Sep 2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.135	0.086	(0.049)	(36.5%)
Day-Ahead with Unallocated Congestion	0.135	0.118	(0.017)	(12.7%)
RTO Reliability	0.023	0.052	0.029	125.5%
East Reliability	0.028	0.031	0.004	13.6%
West Reliability	0.151	0.004	(0.146)	(97.3%)
RTO Deviation	0.947	0.886	(0.061)	(6.5%)
East Deviation	0.242	2.193	1.951	804.8%
West Deviation	0.129	0.118	(0.011)	(8.2%)
Lost Opportunity Cost	1.337	0.861	(0.475)	(35.6%)
Canceled Resources	0.030	0.001	(0.029)	(95.3%)

Table 4-12 shows the operating reserve cost of a 1 MW transaction during the first nine months of 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $3.782 per MWh with a maximum rate of $33.056 per MWh, a minimum rate of $0.147 per MWh and a standard deviation of $5.607 per MWh.

The rates in the table include all operating reserve charges including RTO deviation charges and unallocated congestion charges. Table 4-12 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-12 Operating reserve rates statistics ($/MWh): January through September 2013

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	33.024	3.663	0.024	5.613
	DEC	33.056	3.782	0.147	5.607
	DA Load	0.646	0.119	0.000	0.072
	RT Load	3.610	0.076	0.000	0.250
	Deviation	33.024	3.663	0.024	5.613
West	INC	15.997	1.726	0.024	1.991
	DEC	16.376	1.844	0.130	2.010
	DA Load	0.646	0.119	0.000	0.072
	RT Load	0.802	0.053	0.000	0.092
	Deviation	15.997	1.726	0.024	1.991

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated to real-time load across the entire RTO. These charges are allocated daily based on the real-time load ratio share of each network customer. Even though reactive services rates are not published, a local voltage support rate for each control zone can be calculated, also a reactive transfer interface support rate can calculated for the entire RTO.

Table 4-13 shows the reactive services rates associated with local voltage support for the first nine months of 2012 and 2013. Table 4-13 shows that in the first nine months of 2013 the DPL control zone had the highest rate. Real-time load in the DPL control zone paid an average of $1.952 per MWh for reactive services associated with local voltage support, $1.095 or 127.8 percent higher than the average rate paid in the first nine months of 2012.

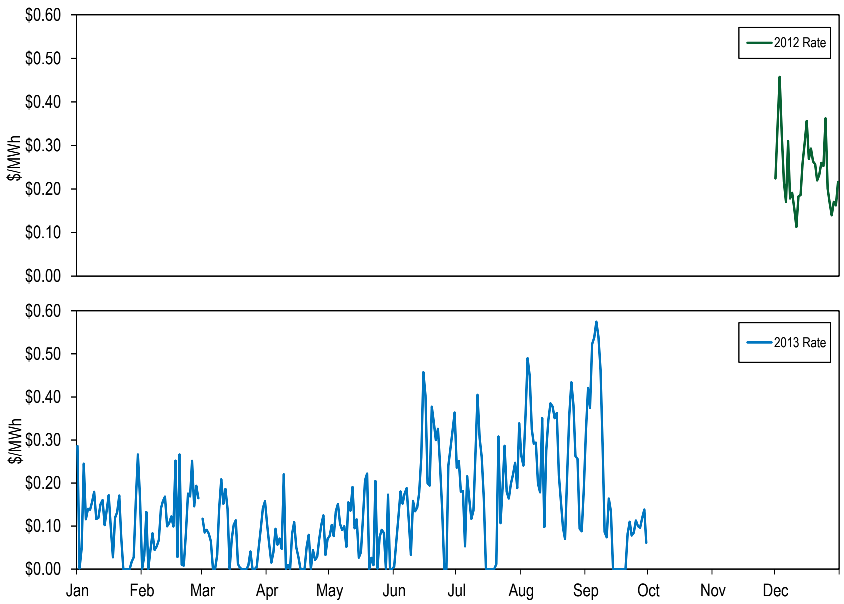
Table 4-13 Local voltage support rates: January through September 2012 and 2013

Control Zone	Jan - Sep 2012 ($/MWh)	Jan - Sep 2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
AECO	0.069	0.269	0.200	288.6%
AEP	0.005	0.034	0.029	529.9%
AP	0.002	0.001	(0.001)	(46.6%)
ATSI	0.219	0.631	0.412	188.5%
BGE	0.107	0.279	0.173	161.8%
ComEd	0.001	0.002	0.001	108.8%
DAY	0.003	0.000	(0.003)	(100.0%)
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.001	0.000	(0.001)	(100.0%)
Dominion	0.014	0.030	0.015	106.1%
DPL	0.857	1.952	1.095	127.8%
EKPC	NA	0.010	NA	NA
JCPL	0.131	0.426	0.294	224.2%
Met-Ed	0.023	0.025	0.002	8.2%
PECO	0.031	0.021	(0.010)	(32.9%)
PENELEC	0.435	1.557	1.122	258.1%
Pepco	0.077	0.011	(0.066)	(85.3%)
PPL	0.083	0.025	(0.058)	(69.4%)
PSEG	0.145	0.264	0.119	82.3%
RECO	0.018	0.002	(0.016)	(89.7%)

Figure 4-5 shows the daily RTO wide reactive transfer interface rate for 2012 and 2013. PJM began allocating these operating reserve charges to reactive services on December 1, 2012. This rate is charged to real-time load in the entire RTO. The average rate in the first nine months of 2013 was $0.141 per MWh. The increase in this reactive rate in the second half of 2013 has been in part a result of the inclusion of FMU adders in the cost-based offers of some of the units routinely used for this service. These units are eligible for FMU adders because they are being offer capped.[14]

14 See OATT Attachment K - Appendix § 6.4.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2012 and 2013



Operating Reserve Determinants

Table 4-14 shows the determinants used to allocate the regional balancing operating reserve charges for the first nine months of 2012 and 2013. Total real-time load and real-time exports were 3,803,726 MWh or 0.6 percent lower in the first nine months of 2013 compared to the first nine months of 2012. Total deviations summed across the demand, supply, and generator categories were lower in the first nine months of 2013 compared to the first nine months of 2012 by 16,033,525 MWh or 14.5 percent.

Table 4-14 Balancing operating reserve determinants (MWh): January through September 2012 and 2013

		Reliability Charge Determinants			Deviation Charge Determinants			
		Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
Jan - Sep 2012	RTO	583,065,065	19,828,074	602,893,139	65,533,983	20,045,419	24,632,266	110,211,669
	East	277,605,000	7,555,552	285,160,552	37,727,176	11,735,893	11,101,723	60,564,793
	West	305,460,065	12,272,522	317,732,587	27,568,221	8,261,711	13,530,543	49,360,475
Jan - Sep 2013	RTO	583,845,687	15,243,726	599,089,413	55,395,477	14,788,584	23,994,082	94,178,144
	East	278,332,308	7,065,335	285,397,643	29,619,798	7,442,437	10,339,554	47,401,790
	West	305,513,379	8,178,391	313,691,770	24,021,589	6,934,081	13,654,528	44,610,197
Difference	RTO	780,622	(4,584,348)	(3,803,726)	(10,138,506)	(5,256,835)	(638,184)	(16,033,525)
	East	727,308	(490,217)	237,091	(8,107,378)	(4,293,456)	(762,169)	(13,163,003)
	West	53,314	(4,094,131)	(4,040,817)	(3,546,632)	(1,327,630)	123,985	(4,750,277)

Deviations fall into three categories, demand, supply and generator deviations. Table 4-15 shows the different categories by the type of transactions that incur deviations. In the first nine months of 2013, 18.7 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 81.3 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-15 Deviations by transaction type: January through September 2013

		Deviation (MWh)			Share		
Deviation Category	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	844,002	388,397	455,605	0.9%	0.8%	1.0%
	DECs Only	5,723,448	2,141,817	1,827,541	6.1%	4.5%	4.1%
	Exports Only	4,036,620	2,145,161	1,891,460	4.3%	4.5%	4.2%
	Load Only	36,512,008	21,494,424	15,017,584	38.8%	45.3%	33.7%
	Combination with DECs	4,135,069	2,297,043	1,838,026	4.4%	4.8%	4.1%
	Combination without DECs	4,144,329	1,152,955	2,991,374	4.4%	2.4%	6.7%
Supply	Bilateral Purchases Only	1,057,097	724,654	332,443	1.1%	1.5%	0.7%
	Imports Only	5,963,091	3,048,405	2,914,685	6.3%	6.4%	6.5%
	INCs Only	4,189,936	1,204,325	2,573,544	4.4%	2.5%	5.8%
	Combination with INCs	3,517,793	2,411,681	1,106,112	3.7%	5.1%	2.5%
	Combination without INCs	60,668	53,371	7,296	0.1%	0.1%	0.0%
Generators		23,994,082	10,339,554	13,654,528	25.5%	21.8%	30.6%
Total		94,178,144	47,401,790	44,610,197	100.0%	100.0%	100.0%

Operating Reserve Credits

Table 4-16 shows the totals for each credit category for the first nine months of 2012 and 2013. During the first nine months of 2013, 49.9 percent of total operating reserve credits were in the balancing category. This percentage decreased 22.5 percentage points from the 72.4 percent in the first nine months of 2012. This decrease was in part due to the reallocation of operating reserve credits paid to units providing black start services and reactive services.

Table 4-16 Credits by operating reserve category: January through September 2012 and 2013

Category	Type	Jan - Sep 2012	Jan - Sep 2013	Change	Percentage Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Day-Ahead	Generators	$85,263,553	$53,563,623	($31,699,930)	(37.2%)	17.5%	8.5%
	Imports	$554	$9	($545)	(98.3%)	0.0%	0.0%
	Load Response	$78	$3,561	$3,483	4,451.1%	0.0%	0.0%
Balancing	Canceled Resources	$3,318,201	$134,109	($3,184,091)	(96.0%)	0.7%	0.0%
	Generators	$194,958,978	$234,006,802	$39,047,824	20.0%	39.9%	37.0%
	Imports	$48,972	$38,615	($10,357)	(21.1%)	0.0%	0.0%
	Load Response	$312,803	$182,396	($130,407)	(41.7%)	0.1%	0.0%
	Local Constraints Control	$7,530,727	$75,638	($7,455,089)	(99.0%)	1.5%	0.0%
	Lost Opportunity Cost	$147,319,459	$81,340,487	($65,978,972)	(44.8%)	30.2%	12.8%
Reactive Services	Day-Ahead	$0	$166,557,630	$166,557,630	NA	0.0%	26.3%
	Local Constraints Control	$37,266	$106,287	$69,022	185.2%	0.0%	0.0%
	Lost Opportunity Cost	$2,291,578	$3,492,177	$1,200,599	52.4%	0.5%	0.6%
	Reactive Services	$46,880,481	$24,065,823	($22,814,658)	(48.7%)	9.6%	3.8%
	Synchronous Condensing	$143,738	$216,968	$73,230	50.9%	0.0%	0.0%
Synchronous Condensing		$71,643	$396,245	$324,602	453.1%	0.0%	0.1%
Black Start Services	Day-Ahead	$0	$66,657,166	$66,657,166	NA	0.0%	10.5%
	Balancing	$0	$2,012,039	$2,012,039	NA	0.0%	0.3%
	Testing	$0	$295,411	$295,411	NA	0.0%	0.0%
Total		$488,178,030	$633,144,987	$144,966,957	29.7%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-17 shows the distribution of total operating reserve credits by unit type for the first nine months of 2012 and 2013. Credits paid to combined cycle units increased 248.3 percent or $121.2 million, mainly due to units providing relief for transmission constraints and supporting the Con Edison – PSEG wheeling contracts during days with high natural gas prices. In the first nine months of 2013, 26.9 percent of all operating reserve credits paid to units were paid to combined cycle units, 16.9 percentage points more than the share in the first nine months of 2012.

Table 4-17 Operating reserve credits by unit type: January through September 2012 and 2013

Unit Type	Jan - Sep 2012	Jan - Sep 2013	Change	Percentage Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Combined Cycle	$48,838,002	$170,078,457	$121,240,455	248.3%	10.0%	26.9%
Combustion Turbine	$188,821,294	$127,054,534	($61,766,761)	(32.7%)	38.7%	20.1%
Diesel	$3,557,166	$6,129,798	$2,572,632	72.3%	0.7%	1.0%
Hydro	$270,027	$201,199	($68,828)	(25.5%)	0.1%	0.0%
Nuclear	$337,984	$126,510	($211,473)	(62.6%)	0.1%	0.0%
Steam - Coal	$208,382,502	$290,949,199	$82,566,698	39.6%	42.7%	46.0%
Steam - Other	$33,071,399	$28,764,870	($4,306,529)	(13.0%)	6.8%	4.5%
Wind	$4,537,250	$9,615,836	$5,078,586	111.9%	0.9%	1.5%
Total	$487,815,623	$632,920,404	$145,104,780	29.7%	100.0%	100.0%

Table 4-18 shows the distribution of operating reserve credits by category and by unit type in the first nine months of 2013. Combined cycle units received 46.7 percent of the day-ahead generator credits in the first nine months of 2013, 30.2 percentage points higher than the share received in the first nine months of 2012. Combined cycle units received 52.6 percent of the balancing generator credits in the first nine months of 2013, 41.5 percentage points higher than the share received in the first nine months of 2012. Combustion turbines and diesels received 73.7 percent of the lost opportunity cost credits, 18.0 percentage points lower than the share received in the first nine months of 2012.

Table 4-18 Operating reserve credits by unit type: January through September 2013

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	46.7%	52.6%	0.0%	13.7%	7.0%	8.3%	0.0%	0.0%
Combustion Turbine	12.3%	21.7%	23.3%	60.1%	73.5%	4.7%	100.0%	0.4%
Diesel	0.1%	0.3%	0.0%	16.2%	0.2%	2.7%	0.0%	0.0%
Hydro	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
Steam - Coal	35.7%	15.2%	24.2%	10.1%	7.3%	83.1%	0.0%	99.6%
Steam - Others	5.1%	10.1%	52.6%	0.0%	0.2%	1.1%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	11.7%	0.0%	0.0%	0.0%
Total	$53,563,623	$234,006,802	$134,109	$75,638	$81,340,484	$194,438,886	$396,245	$68,964,616

Table 4-18 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In the first nine months of 2013, combined cycle and coal units received 91.4 percent of all reactive services credits, 9.4 percentage points higher than the share received in the first nine months of 2012. Synchronous condensing was only provided by combustion turbines. Coal units received 99.6 percent of all black start services credits.

Economic and Noneconomic Generation[15]

Economic generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 4-19 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost.

15 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load costs and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits because total energy revenues covered total hourly costs for the day or segment. In the first nine months of 2013, 33.0 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 31.8 percent of the real-time generation was eligible for balancing operating reserve credits.[16]

Table 4-19 Day-ahead and real-time generation (GWh): January through September 2013

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	610,622	201,481	33.0%
Real-Time	600,784	191,150	31.8%

Table 4-20 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first nine months of 2013, 81.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.1 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 4-20 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

Table 4-20 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through September 2013

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	164,644	36,836	81.7%	18.3%
Real-Time	128,346	62,803	67.1%	32.9%

16 In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that operate as requested by PJM are eligible for balancing operating reserve credits.

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment scheduled or committed is noneconomic, including no load and startup costs. Table 4-21 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2013, 5.5 percent of the day-ahead generation eligible for operating reserve credits received credits and 8.4 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-21 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through September 2013

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	201,481	10,994	5.5%
Real-Time	191,150	15,971	8.4%

Geography of Charges and Credits

Table 4-22 shows the geography of charges and credits in the first nine months of 2013. Table 4-22 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Table 4-22 Geography of regional charges and credits: January through September 2013[17,18]

					Shares			
Location		Charges	Credits	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$5,163,143	$3,411,012	($1,752,131)	1.4%	0.9%	1.3%	0.0%
	AEP	$33,513,218	$26,041,796	($7,471,422)	9.1%	7.1%	5.3%	0.0%
	AP - DLCO	$19,341,396	$14,997,060	($4,344,336)	5.2%	4.1%	3.1%	0.0%
	ATSI	$16,408,214	$19,059,648	$2,651,434	4.4%	5.2%	0.0%	1.9%
	BGE - Pepco	$34,304,948	$27,361,959	($6,942,990)	9.3%	7.4%	5.0%	0.0%
	ComEd - External	$28,739,224	$21,202,293	($7,536,931)	7.8%	5.7%	5.4%	0.0%
	DAY - DEOK	$12,793,338	$1,944,208	($10,849,130)	3.5%	0.5%	7.8%	0.0%
	Dominion	$33,866,930	$41,591,240	$7,724,311	9.2%	11.3%	0.0%	5.5%
	DPL	$10,495,875	$12,400,223	$1,904,349	2.8%	3.4%	0.0%	1.4%
	JCPL	$11,674,009	$13,497,524	$1,823,515	3.2%	3.7%	0.0%	1.3%
	Met-Ed	$8,728,397	$3,877,581	($4,850,815)	2.4%	1.1%	3.5%	0.0%
	PECO	$22,048,815	$5,374,156	($16,674,659)	6.0%	1.5%	11.9%	0.0%
	PENELEC	$14,988,170	$4,205,716	($10,782,453)	4.1%	1.1%	7.7%	0.0%
	PPL	$23,317,583	$27,825,550	$4,507,967	6.3%	7.5%	0.0%	3.2%
	PSEG	$24,697,034	$146,255,051	$121,558,017	6.7%	39.6%	0.0%	86.7%
	RECO	$951,869	$0	($951,869)	0.3%	0.0%	0.7%	0.0%
	All Zones	$301,032,162	$369,045,018	$68,012,856	81.6%	100.0%	51.6%	100.0%
Hubs and Aggregates	AEP - Dayton	$2,070,078	$0	($2,070,078)	0.6%	0.0%	1.5%	0.0%
	Dominion	$2,606,602	$0	($2,606,602)	0.7%	0.0%	1.9%	0.0%
	Eastern	$300,965	$0	($300,965)	0.1%	0.0%	0.2%	0.0%
	New Jersey	$762,184	$0	($762,184)	0.2%	0.0%	0.5%	0.0%
	Ohio	$97,084	$0	($97,084)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$1,248,123	$0	($1,248,123)	0.3%	0.0%	0.9%	0.0%
	Western	$15,374,493	$0	($15,374,493)	4.2%	0.0%	11.0%	0.0%
	RTEP B0328 Source	$32	$0	($32)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$22,459,560	$0	($22,459,560)	6.1%	0.0%	16.0%	0.0%
Interfaces	CPLE Imp	$4,079	$0	($4,079)	0.0%	0.0%	0.0%	0.0%
	Hudson	$280,705	$0	($280,705)	0.1%	0.0%	0.2%	0.0%
	IMO	$5,075,114	$0	($5,075,114)	1.4%	0.0%	3.6%	0.0%
	Linden	$1,719,562	$0	($1,719,562)	0.5%	0.0%	1.2%	0.0%
	MISO	$5,979,439	$0	($5,979,439)	1.6%	0.0%	4.3%	0.0%
	Neptune	$924,747	$0	($924,747)	0.3%	0.0%	0.7%	0.0%
	NIPSCO	$22,773	$0	($22,773)	0.0%	0.0%	0.0%	0.0%
	Northwest	$165,190	$0	($165,190)	0.0%	0.0%	0.1%	0.0%
	NYIS	$7,814,553	$0	($7,814,553)	2.1%	0.0%	5.6%	0.0%
	OVEC	$1,252,475	$0	($1,252,475)	0.3%	0.0%	0.9%	0.0%
	South Exp	$4,959,166	$0	($4,959,166)	1.3%	0.0%	3.5%	0.0%
	South Imp	$17,171,527	$0	($17,171,527)	4.7%	0.0%	12.3%	0.0%
	All Interfaces	$45,369,330	$38,624	($45,330,706)	12.3%	0.0%	32.4%	0.0%
	Total	$368,861,052	$369,083,642	$222,590	100.0%	100.0%	100.0%	100.0%

17 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-22 does not include synchronous condensing and local constraint control charges and credits since these are allocated zonally.
18 The total balance should be zero but due to resettlements performed while this report was been developed, total operating reserve charges do not match total operating reserve credits.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AECO Control Zone paid 1.4 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.9 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had an 1.3 percent share of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the PSEG Control Zone paid 6.7 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 39.6 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had an 86.9 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-22 also shows that 81.6 percent of all charges were allocated in control zones, 6.1 percent in hubs and aggregates and 12.3 percent in interfaces.

Table 4-23 and Table 4-24 compare the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generator charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.

Table 4-23 shows that on average, 15.0 percent of the RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges were paid by generators deviating in the Eastern Region while these generators received 75.6 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 4-23 Monthly balancing operating reserve charges and credits to generators (Eastern Region): January through September 2013

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,070,070	$7,239,642	$1,239,705	$10,549,416	$67,203,566
Feb	$596,857	$11,853,340	$474,443	$12,924,640	$62,194,876
Mar	$580,957	$576,090	$745,649	$1,902,696	$10,854,917
Apr	$989,136	$1,382,976	$576,404	$2,948,515	$18,105,690
May	$942,411	$202,584	$992,435	$2,137,429	$11,303,585
Jun	$686,381	$147,673	$769,465	$1,603,519	$12,220,617
Jul	$1,468,567	$506,086	$2,355,842	$4,330,495	$27,570,665
Aug	$529,501	$139,205	$581,930	$1,250,637	$8,425,775
Sep	$1,130,682	$461,835	$1,094,912	$2,687,430	$20,540,790
East Generators Total	$8,994,562	$22,509,431	$8,830,784	$40,334,777	$238,420,481
PJM Total	$83,398,256	$103,969,585	$81,252,002	$268,619,843	$315,520,013
Share	10.8%	21.7%	10.9%	15.0%	75.6%

Table 4-24 also shows that generators in the Western Region paid 13.9 percent of the RTO and Western Region balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 24.3 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 4-24 Monthly balancing operating reserve charges and credits to generators (Western Region): January through September 2013

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,545,383	$156,268	$1,707,943	$4,409,594	$11,986,551
Feb	$894,132	$54,981	$582,626	$1,531,739	$4,913,999
Mar	$859,696	$59,092	$1,007,486	$1,926,274	$6,606,397
Apr	$1,390,711	$18,514	$930,462	$2,339,687	$4,972,019
May	$1,121,750	$470,387	$1,296,967	$2,889,105	$11,214,216
Jun	$825,243	$223,560	$914,667	$1,963,470	$5,602,110
Jul	$1,602,805	$332,867	$2,410,705	$4,346,377	$16,347,409
Aug	$770,345	$119,450	$779,656	$1,669,452	$5,628,395
Sep	$1,401,325	$71,651	$1,137,948	$2,610,924	$9,478,927
West Generators Total	$11,411,391	$1,506,770	$10,768,460	$23,686,620	$76,750,024
PJM Total	$83,398,256	$5,282,696	$81,252,002	$169,932,953	$315,520,013
Share	13.7%	28.5%	13.3%	13.9%	24.3%

Table 4-25 Percentage of unit credits and charges of total credits and charges: 2012 and 2013

	2012		2013	
	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits
Jan	10.8%	99.9%	12.2%	100.0%
Feb	8.2%	100.0%	15.0%	100.0%
Mar	11.7%	99.8%	8.4%	99.9%
Apr	13.6%	100.0%	10.2%	100.0%
May	14.0%	100.0%	8.6%	100.0%
Jun	13.6%	99.9%	6.2%	99.9%
Jul	15.6%	99.8%	11.0%	99.9%
Aug	14.6%	100.0%	5.2%	99.9%
Sep	9.4%	100.0%	6.2%	100.0%
Oct	12.7%	99.9%		
Nov	12.6%	99.8%		
Dec	8.8%	100.0%		
Average (Jan - Sep)	12.7%	99.9%	9.8%	100.0%
Average	12.3%	99.9%		

Table 4-25 shows that on average in the first nine months of 2013, operating reserve charges paid by generators were 9.8 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 2.9 percentage points lower than the average in the first nine months of 2012. Generators received 99.96 percent of all operating reserve credits, while the remaining 0.04 percent were credits paid to import transactions, load response resources and unallocated congestion charges.

Reactive services charges are allocated by zone or zones where the service is provided, and charged to real-time load of the zone or zones. The costs of running units that provide reactive services to the entire RTO Region are allocated to the entire RTO real-time load. Table 4-26 shows the geography of reactive services charges. In the first nine months of 2013, 53.3 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 4.4 percent were paid by real-time load in multiple zones and 42.3 percent were paid by real-time load across the entire RTO. In the first nine months of 2013, resources in two control zones accounted for 99.7 percent of all reactive services costs allocated across the entire RTO.

Table 4-26 Geography of reactive services charges: January through September, 2013[19]

Location	Charges	Share of Charges
Single Zone	$103,618,183	53.3%
Multiple Zones	$8,543,206	4.4%
Entire RTO	$82,171,210	42.3%
Total	$194,332,599	100.0%

In the first nine months of 2013, the top three zones accounted for 76.4 percent of all the reactive services charges allocated to single zones.

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 99.6 percent of all the black start services costs in the first nine months of 2013. These costs resulted from noneconomic operation of units providing black start service under the Automatic Load Rejection (ALR) option in the AEP Control Zone.

Synchronous condensing charges are allocated by zone. Resources in five control zones accounted for all synchronous condensing costs in the first nine months of 2013.[20]

Operating Reserve Issues

Concentration of Operating Reserve Credits

There continues to be a high level of concentration in the units and companies receiving operating reserve credits. This concentration results from a combination of unit operating characteristics, PJM's persistent need for operating reserves in particular locations and the fact that the lack of transparency makes it impossible for competition to affect operating reserve credit payments.

The concentration of operating reserve credits is first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The focus on the top 10 units is illustrative.

The concentration of operating reserve credits in the top 10 units remains high and it increased in the first nine months of 2013 compared to the first nine months of 2012. Table 4-27 shows that the top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 34.5 percent of total operating reserve credits in the first nine months of 2013, compared to 21.1 percent in the first nine months of 2012. The increase in the concentration of operating reserve credits was in part the result of lower lost opportunity cost credits paid to combustion turbines and diesels in the first nine months of 2013 compared to the first nine months of 2012, which increased the share of credits paid to the top 10 units receiving day-ahead operating reserve, balancing operating reserve, reactive services and black start services credits.

Table 4-27 Top 10 operating reserve credits units (By percent of total system): January through September 2012 and 2013

	Top 10 Units Credit Share	Percent of Total PJM Units
Jan - Sep 2012	21.1%	0.7%
Jan - Sep 2013	34.5%	0.7%

Table 4-28 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserve categories paid to generators. The shares of the top 10 organizations in all categories separately were above 82.0 percent.

19 PJM and the MMU cannot publish more detailed information about the location of the costs of reactive services because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

20 PJM and the MMU cannot publish more detailed information about the location of the costs of synchronous condensing because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

Table 4-28 Top 10 units and organizations operating reserve credits: January through September 2013

		Top 10 units		Top 10 organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$32,162,611	60.0%	$48,379,427	90.3%
Balancing	Canceled Resources	$130,276	97.1%	$134,109	100.0%
	Generators	$134,520,722	57.5%	$209,181,362	89.4%
	Local Constraints Control	$71,358	94.3%	$75,638	100.0%
	Lost Opportunity Cost	$21,546,524	26.5%	$67,402,432	82.9%
Reactive Services		$120,569,775	62.0%	$185,419,966	95.4%
Synchronous Condensing		$161,775	40.8%	$396,245	100.0%
Black Start Services		$55,719,297	80.8%	$68,957,888	100.0%
Total		$218,664,826	34.5%	$544,955,010	86.1%

Table 4-29 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first nine months of 2013, 90.1 percent of all credits paid to these units were allocated to deviations while the remaining 9.9 percent were paid for reliability reasons.

Table 4-29 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through September 2013

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$10,550,254	$2,804,123	$0	$33,028,025	$88,138,320	$0	$134,520,722
Share	7.8%	2.1%	0.0%	24.6%	65.5%	0.0%	100.0%

Table 4-30 Daily operating reserve credits HHI: January through September 2013

Category	Type	Average	Minimum	Maximum	Highest market share (One day)	Highest market share (All days)
Day-Ahead	Generators	5343	1254	10000	100.0%	55.7%
	Imports	10000	10000	10000	100.0%	38.1%
	Load Response	10000	10000	10000	100.0%	100.0%
Balancing	Canceled Resources	10000	10000	10000	100.0%	52.6%
	Generators	3927	1084	9888	99.4%	48.4%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	92.8%
	Lost Opportunity Cost	4699	829	10000	100.0%	24.2%
Reactive Services		4797	1852	10000	100.0%	53.9%
Synchronous Condesing		8497	5002	10000	100.0%	74.0%
Black Start Services		9894	6160	10000	100.0%	99.6%
Total		9894	6160	10000	85.1%	23.1%

In the first nine months of 2013, concentration in all operating reserve credit categories was high.[21,22] The HHI for operating reserve credits was calculated based on each organization's daily credits for each category. Table 4-30 shows the average HHI for each category. HHI for day-ahead operating reserve credits was 5343, for balancing operating reserve generator credits was 3927 and for lost opportunity cost credits was 4699.

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirement (from automatic load rejection units); local contingencies not seen in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[23] Participants can submit units as self-scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant cannot set LMP and is not eligible for day-ahead operating reserve credits.[24] Units scheduled as must run by PJM may set LMP if raised above economic minimum and are eligible for day-ahead operating reserve credits.

Table 4-31 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first nine months of 2013, 4.7 percent of the total day-ahead generation was scheduled as must run by PJM, 1.9 percentage points higher than the first nine months of 2012.[25]

21 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
22 Table 4-30 excludes the local constraints control categories.
23 See "Item 12 - October 2012 MIC DAM Cost Allocation," from PJM's MIC meeting <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>.
24 See "PJM eMkt Users Guide," Section Managing Unit Data (version July 9, 2013) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>
25 PJM increased the amount of generation scheduled as must run on September 13, 2012. See *2012 State of the Market Report for PJM*: Volume II, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

Table 4-31 Day-ahead generation scheduled as must run by PJM: 2012 and 2013

	2012			2013		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	71,152	1,312	1.8%	72,681	2,907	4.0%
Feb	63,642	1,191	1.9%	65,632	2,474	3.8%
Mar	60,513	1,109	1.8%	67,940	3,178	4.7%
Apr	55,999	1,099	2.0%	57,570	2,522	4.4%
May	62,986	1,944	3.1%	61,169	2,848	4.7%
Jun	69,190	1,841	2.7%	68,452	3,724	5.4%
Jul	82,984	3,618	4.4%	78,639	4,395	5.6%
Aug	76,161	2,438	3.2%	73,783	3,678	5.0%
Sep	63,535	2,902	4.6%	64,757	3,162	4.9%
Oct	60,656	3,509	5.8%			
Nov	62,985	3,542	5.6%			
Dec	68,759	2,347	3.4%			
Total (Jan - Sep)	606,162	17,453	2.9%	610,622	28,888	4.7%
Total	798,561	26,851	3.4%			

Pool-scheduled units are made whole in the Day-Ahead Energy Market if their total offer (including no load and startup costs) is greater than the revenues from the Day-Ahead Energy Market. Such units are paid day-ahead operating reserve credits. Pool-scheduled units scheduled as must run by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market. It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-32 shows the total day-ahead generation scheduled as must run by PJM by category. In the first nine months of 2013, 65.4 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 13.4 percent were credits paid to units scheduled to provide black start services, 40.7 percent were credits paid to units scheduled to provide reactive services and 11.3 percent were normal day-ahead operating reserve credits paid to units scheduled noneconomic. The remaining 34.6 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-32 Day-ahead generation scheduled as must run by PJM by category (GWh): 2013

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	433	1,271	250	954	2,907
Feb	430	1,356	206	481	2,474
Mar	424	909	490	1,354	3,178
Apr	451	840	439	792	2,522
May	429	1,058	346	1,016	2,848
Jun	484	1,601	459	1,181	3,724
Jul	420	1,616	234	2,124	4,395
Aug	465	1,644	387	1,182	3,678
Sep	338	1,460	453	911	3,162
Total	3,875	11,754	3,264	9,994	28,888
Share	13.4%	40.7%	11.3%	34.6%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2013 were $28.8 million, of which 53.7 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets in order to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. The overall goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in day-ahead but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit has to pay. For purposes of this report, this lost opportunity cost will be referred to as day-ahead lost opportunity cost.[26] If a unit generating in real time with an offer price lower than the LMP at the unit's bus is reduced or suspended by PJM due to a transmission constraint or other reliability issue, the unit will receive a credit for lost opportunity cost based on the desired output. For purposes of this report, this lost opportunity cost will be referred as real-time lost opportunity cost.

In the first nine months of 2013, lost opportunity cost credits decreased by \$66.0 million or 44.8 percent compared to the first nine months of 2012. The decrease of \$66.0 million is comprised of a decrease of \$74.7 million in day-ahead lost opportunity cost and an increase of \$8.7 million in real-time lost opportunity cost. Table 4-35 shows the monthly composition of lost opportunity cost credits in 2012 and 2013.

Day-ahead lost opportunity cost (payments to combustion turbines and diesels scheduled in the Day-Ahead Market and not requested in real time) continue to comprise the majority of lost opportunity cost credits. In the first nine months of 2013, day-ahead lost opportunity cost were 74.2 percent of all lost opportunity cost credits. Combustion turbines and diesels are only eligible for day-ahead lost opportunity cost if the units are scheduled in day ahead and follow PJM instructions in real time.[27] Table 4-34 shows, for combustion turbines and diesels scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits. In the first nine months of 2013, PJM scheduled 11,060 GWh from combustion turbines and diesels, of which 44.1 percent was not requested by PJM in real time and of which 32.4 percent received lost opportunity cost credits, 17.7 percentage points lower than the first nine months of 2012.

Table 4-33 Monthly lost opportunity cost credits: 2012 and 2013

	2012			2013		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$5,116,947	$332,282	$5,449,229	$8,862,207	$2,752,980	$11,615,188
Feb	$4,277,162	$366,971	$4,644,133	$2,050,724	$2,681,143	$4,731,868
Mar	$10,327,361	$450,299	$10,777,660	$4,854,970	$2,350,261	$7,205,230
Apr	$11,814,780	$696,258	$12,511,038	$3,893,834	$1,548,469	$5,442,303
May	$15,806,150	$3,502,912	$19,309,062	$5,357,701	$3,247,699	$8,605,401
Jun	$14,502,682	$677,375	$15,180,057	$6,235,079	$807,362	$7,042,441
Jul	$27,875,651	$3,066,115	$30,941,767	$17,250,646	$3,071,292	$20,321,938
Aug	$25,573,420	$1,346,343	$26,919,763	$5,455,830	$173,290	$5,629,120
Sep	$19,723,184	$1,863,565	$21,586,749	$6,377,820	$4,369,174	$10,746,995
Oct	$12,391,362	$7,990,739	$20,382,101			
Nov	$14,541,552	$4,094,304	$18,635,855			
Dec	$5,177,551	$1,139,539	$6,317,091			
Total (Jan - Sep)	$135,017,338	$12,302,120	$147,319,459	$60,338,812	$21,001,671	$81,340,484
Share (Jan - Sep)	91.6%	8.4%	100.0%	74.2%	25.8%	100.0%
Total	$167,127,804	$25,526,703	$192,654,507			
Share	86.8%	13.2%	100.0%			

26 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market subtracted by the expected costs (valued at the unit's offer curve cleared in day ahead). A unit scheduled in the Day-Ahead Energy Market and not called in real time incurs in balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

27 Combustion turbines and diesels with lead times of two hours or less are automatically eligible for lost opportunity cost credits. Combustion turbines and diesels with lead times greater than two hours are assumed to be committed in real time for the duration of their day-ahead schedule unless instructed not to run by PJM.

Table 4-34 Day-ahead generation from combustion turbines and diesels (GWh): 2012 and 2013

	2012			2013		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	579	439	377	886	638	565
Feb	758	590	546	430	206	173
Mar	1,392	1,076	921	809	397	283
Apr	1,872	1,432	1,249	684	325	256
May	1,928	1,250	1,047	1,031	389	262
Jun	2,588	1,624	1,235	1,284	699	442
Jul	3,900	1,424	988	2,950	963	761
Aug	2,358	1,386	1,125	1,769	779	545
Sep	1,635	1,169	1,032	1,217	480	295
Oct	1,079	895	797			
Nov	1,319	1,018	823			
Dec	851	678	625			
Total (Jan - Sep)	17,009	10,391	8,521	11,060	4,878	3,582
Share (Jan - Sep)	100.0%	61.1%	50.1%	100.0%	44.1%	32.4%
Total	20,258	12,981	10,765			
Share	100.0%	64.1%	53.1%			

Table 4-35 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2012 and 2013

	2012			2013		
	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule	Total	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule	Total
Jan	$4,857,442	$355,007	$5,212,449	$8,166,901	$695,307	$8,862,207
Feb	$4,382,996	$154,019	$4,537,015	$1,860,546	$190,178	$2,050,724
Mar	$9,661,923	$894,042	$10,555,965	$3,031,710	$1,823,260	$4,854,970
Apr	$10,846,998	$1,028,201	$11,875,199	$2,476,452	$1,417,382	$3,893,834
May	$12,925,885	$2,775,886	$15,701,771	$3,686,814	$1,670,887	$5,357,701
Jun	$12,550,655	$2,163,079	$14,713,734	$4,785,844	$1,449,235	$6,235,079
Jul	$13,911,706	$13,967,989	$27,879,694	$8,278,481	$8,972,165	$17,250,646
Aug	$22,219,006	$3,415,961	$25,634,967	$3,383,866	$2,071,965	$5,455,830
Sep	$17,783,763	$2,196,639	$19,980,402	$4,200,542	$2,177,278	$6,377,820
Oct	$11,185,166	$1,296,974	$12,482,141			
Nov	$12,704,380	$2,130,370	$14,834,749			
Dec	$4,979,204	$364,570	$5,343,774			
Total (Jan - Sep)	$109,140,374	$26,950,822	$136,091,196	$39,871,156	$20,467,656	$60,338,812
Share (Jan - Sep)	80.2%	19.8%	100.0%	66.1%	33.9%	100.0%
Total	$138,009,125	$30,742,736	$168,751,861			
Share	81.8%	18.2%	100.0%			

In the first nine months of 2013, the top three control zones in which generation received lost opportunity cost credits, AEP, ComEd and Dominion, accounted for 60.7 percent of all lost opportunity cost credits, 53.6 percent of all the day-ahead generation from combustion turbines and diesels and 53.9 percent of all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.

Combustion turbines and diesels receive lost opportunity cost credits on an hourly basis. For example, if a combustion turbine is scheduled to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for lost opportunity cost credits for hours 10, 11, 17 and 18. Table 4-35 shows the lost opportunity costs credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market for units that did not run in real time and units that ran in real time for at least one hour of their day-ahead schedule. Table 4-35 shows that in the first nine months of 2013, $39.9 million or 66.1 percent of all lost opportunity cost credits were paid to combustion turbines and diesels that did not run for any hour in real time, 14.1 percentage points lower than the first nine months of 2012.

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-36 shows the total day-ahead generation from combustion turbines and diesels that were not called in real time by PJM and received lost opportunity cost credit. Table 4-36 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP) or economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In the first nine months of 2013, 69.1 percent of the scheduled generation not called by PJM from units receiving lost opportunity cost credits was economic and the remaining 30.9 percent was noneconomic.

Table 4-36 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2012 and 2013[28]

	2012			2013		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	309	136	445	548	121	669
Feb	422	248	670	171	53	224
Mar	805	287	1,092	272	145	417
Apr	1,126	329	1,455	225	93	318
May	875	363	1,237	229	130	359
Jun	835	667	1,501	365	272	636
Jul	826	402	1,228	725	203	928
Aug	946	397	1,343	437	275	712
Sep	880	305	1,185	293	166	459
Oct	710	193	903			
Nov	782	280	1,062			
Dec	434	298	732			
Total (Jan - Sep)	7,024	3,133	10,157	3,264	1,457	4,722
Share (Jan - Sep)	69.2%	30.8%	100.0%	69.1%	30.9%	100.0%
Total	8,950	3,904	12,853			
Share	69.6%	30.4%	100.0%			

The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic.

Lost Opportunity Cost Calculation

On February 17, 2012, the PJM Market Implementation Committee (MIC) endorsed the charge to prepare a proposal to make all energy related lost opportunity costs calculations consistent throughout the PJM rules.[29] PJM and the MMU jointly proposed two specific modifications. The MMU also believes that two additional modifications would be appropriate but the MMU did not formally recommend these to the MIC for consideration although they were brought to the attention of the MIC.

28 The total generation in Table 4-36 is lower than the Day-Ahead Generation not requested in Real Time in Table 4-34 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-36 includes all generation, including generation from units that were not called in real time and did not receive lost opportunity cost credits.

29 See "Meeting Minutes," from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>. (February 17, 2012)

- **Unit Schedule Used:** Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the lost opportunity cost in the energy market. The MMU recommends that the lost opportunity cost in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market.
- **No load and startup costs:** Current rules do not include in the calculation of lost opportunity cost credits all of the costs not incurred by a scheduled unit not running in real time. Generating units do not incur no load or startup costs if they are not dispatched in real time. As a result, no load and startup costs should be subtracted from the real time LMP in the same way that the incremental energy offer is subtracted to calculate the actual value of the opportunity lost by the unit. The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
- **Day-Ahead LMP:** Current rules require the use of the day-ahead LMP as part of the lost opportunity cost calculation logic when a unit is scheduled on a noneconomic basis day ahead, meaning that the unit's offer is greater than the day-ahead LMP. In the Day-Ahead Energy Market, such units receive operating reserve credits equal to the difference between the unit's offer (including no load and startup costs) and the day-ahead LMP. If such a unit is not dispatched in real time, under the current rules the unit receives lost opportunity cost credits equal to the difference between the real-time LMP and the day-ahead LMP. This calculation results in double counting because the unit has already been made whole to its day-ahead offer in the Day-Ahead Energy Market through day-ahead operating reserve credits if necessary. If the unit is not dispatched in real time, it should receive only the difference between real-time LMP and the unit's offer, which is the actual lost opportunity cost. The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
- **Offer Curve:** Current rules require the use of the difference between the real-time LMP and the incremental offer at a single point on the offer curve (at the actual or scheduled output), instead of using the difference between the real-time LMP and the entire offer curve (area between the LMP and the offer curve) when calculating the lost opportunity cost in the PJM Energy Markets for units scheduled in day ahead but which are backed down or not dispatched in real time. Units with an offer lower than the real-time LMP at the units' bus that are reduced in real time by PJM should be paid lost opportunity cost based on the area between the real time LMP and their offer curve between the actual and desired output points. Units scheduled in day ahead and not dispatched in real time should be paid lost opportunity cost based on the area between the real-time LMP and their offer curve between zero output and scheduled output points. The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.

These four modifications are consistent with the inputs used by PJM's software to commit combustion turbines in real time. PJM's commitment process is based on the forecasted LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' schedule on which it is committed.

Table 4-37 shows the impact that each of these changes would have had on the lost opportunity cost credits in the energy market for the first nine months of 2013, for the two categories of lost opportunity cost credits. Energy lost opportunity cost credits would have been reduced by a net of $21.3 million, or 29.0 percent, if all these changes had been implemented.[30]

30 The impacts on the lost opportunity cost credits were calculated following the order presented. Eliminating one of the changes has an effect on the remaining impacts.

Table 4-37 Impact on energy market lost opportunity cost credits of rule changes: January through September 2013

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$21,001,671	$60,338,812	$81,340,484
Impact 1: Committed Schedule	$903,955	$15,033,146	$15,937,101
Impact 2: Eliminating DA LMP	NA	($436,556)	($436,556)
Impact 3: Using Offer Curve	($1,033,747)	$6,231,985	$5,198,238
Impact 4: Including No Load Cost	NA	($32,589,591)	($32,589,591)
Impact 5: Including Startup Cost	NA	($9,360,083)	($9,360,083)
Net Impact	($129,792)	($21,121,099)	($21,250,891)
Credits After Changes	$20,871,880	$39,217,713	$60,089,593

Black Start Service Units

Certain units located in the AEP control zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the Automatic Load Rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start service under the ALR option could remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units results in make whole payments in the form of operating reserve credits. The MMU recommended that these costs be allocated as black start charges. This recommendation was made effective on December 1, 2012.[31]

In the first nine months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $68.7 million, and 95.0 percent of these costs was paid by peak transmission use in the AEP control zone while the remaining 5.0 percent was paid by non-zone peak transmission use. The calculation of peak transmission use is based on the peak load contribution in the AEP control zone. Load in the AEP control zone paid an average of $10.25 per MW-day for black start costs related to the noneconomic operation of ALR units. Non-zone peak transmission use is based on reserved capacity for firm and non-firm transmission service. Point-to-point customers paid an average of $0.07 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

31 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).

PJM and AEP have issued two requests for proposals (RFP) seeking additional black start capability for the AEP control zone. PJM awarded all viable solutions from the last RFP.[32] PJM has approved new rules concerning black start service procurement, and the new selection process will be effective on April 1, 2015.[33,34]

Con Edison – PSEG Wheeling Contracts Support

It appears that certain units located near the boundary between New Jersey and New York City are frequently operated to support the wheeling contracts between Con-Ed and PSEG.[35] These units are often run out-of-merit and receive substantial balancing operating reserve credits. The MMU recommends that this issue be addressed by PJM in order to determine if the cost of running these units is being allocated properly.

Reactive / Voltage Support Units

Certain units located in the BGE and Pepco control zones are committed to provide reactive support to the AP-South interface. The AP-South interface consists of four 500 kV transmission lines that connect the Western and Eastern regions of PJM. PJM approved in the 2012 Regional Transmission Expansion Planning (RTEP) seven reactive upgrades to solve identified N-1-1 low voltage NERC criteria violations, and five of the seven upgrades are located in substations at or near the AP-South interface. These upgrades may reduce the need for noneconomic operation of units to provide reactive support to the AP-South interface, although the results will not be known until the RTEP upgrades are in place.

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[36] Under the rules providing for credits for reactive service,

32 See "Item 3: Black Start RFP Status," from the PJM's System Restoration Strategy Task Force June 14, 2013 meeting. <http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20130614/20130614-item-03-srstf-bs-rfp-status.ashx>.
33 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at "Black Start Service".
34 See "Manual 14D: Generator Operational Requirement" Revision 23 (April 1, 2013) at "Section 10: Black Start Generation Procurement".
35 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions" at "Con Edison and PSE&G Wheeling Contracts" for a description of the contracts.
36 OATT Attachment K - Appendix § 3.2.3B (f).

units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive service credits do not cover a unit's entire offer, the unit is paid through balancing operating reserves. The result is a misallocation of the costs of providing reactive service. Reactive service credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

In the first nine months of 2013, units providing reactive services were paid $7.0 million in balancing operating reserve credits in order to cover their total energy offer.

On October 10, 2012 and November 7, 2012 the MMU presented this issue at PJM's Market Implementation Committee (MIC).[37,38] The MIC endorsed the issue charge and approved merging this issue with the long term solution for the allocation of the cost of day-ahead operating reserves for reliability.[39]

The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with operating reserve credits calculation.

Internal Bilateral Transactions

Market participants are allocated a portion of the costs of operating reserves based on their deviations. Deviations are calculated in three categories, demand, supply and generation. Generators deviate when their real-time output is different than the desired output or their day-ahead scheduled output.[40] Load, interchange transactions, internal bilateral transactions, demand response, increment offers and decrement bids also incur deviations. These transactions are grouped in the demand and supply categories.

Generators are allowed to offset their deviations with other generators at the same bus if the generators have the same electrical impact on the transmission system. Load, interchange transactions, internal bilateral transactions, demand response, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped into two categories, demand and supply and aggregated by location. A negative deviation from one transaction can offset a positive deviation from another transaction in the same category, as long as both transactions are in the same location at the same hour.[41] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset each other's deviations. The same applies to supply transactions such as imports, internal bilateral purchases and increment offers. Unlike all other transaction types, internal bilateral sales and purchases do not impact dispatch or market prices. Internal bilateral transactions are used by participants to transfer the financial responsibility or right of the energy withdrawn or injected into the system in the Day-Ahead and Real-Time Energy Markets.

The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. IBTs should not pay for balancing operating reserves and should not be used to offset other transactions that deviate. IBTs shift the responsibility for an injection or withdrawal in PJM from one participant to another but IBTs are not part of the day-ahead unit commitment process, do not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, and thus IBTs should not be considered in the allocation of balancing operating reserve charges. The use of IBTs has been extended to offset deviations from other transactions that do impact the energy market. The elimination of the use of IBTs in the deviation calculation would eliminate the balancing operating reserve charges to participants that use IBTs only in real time. Such elimination would increase the balancing

37 See "Item 7: Reactive Service and Operating Reserve Credits Problem Statement and Issue Charge," from the PJM's MIC October 10, 2012 meeting. <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-07-reactive-service-and-operating-reserve-credits-problem-statement-and-issue-charge.ashx>.

38 See "Minutes," from PJM's MIC November 7, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20121212/20121212-draft-minutes-mic-20121107.ashx>.

39 PJM created the MIC sub group Day Ahead (DA) Reliability and Reactive Cost Allocation (DARRCA) to address the allocation of the cost of reactive services in day ahead and real time. <http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={323CE736-A41E-49D4-A8AF-687BB3697AE9}> (Accessed January 11, 2013).

40 See OATT 3.2.3 (o) for a complete description of how generators deviate.

41 Locations can be control zones, hubs, aggregates and interfaces. See the *2012 State of the Market Report for PJM, Volume II*, Section 3, "Operating Reserve" at "Description of Operating Reserves" pp. 102-103 for a full description of balancing operating reserve locations.

operating reserve charges to participants that use IBTs to offset deviations from day-ahead transactions.

The impact of eliminating the use of internal bilateral transactions in the calculation of deviations use to allocated balancing operating reserve charges has been aggregated with the impacts of other recommendations.[42]

Up-to Congestion Transactions

Up-to congestion transactions do not pay operating reserve charges. The MMU calculated the impact on operating reserve rates if up-to congestion transactions had paid operating reserve charges based on deviations in the same way that increment offers and decrement bids do, while accounting for the impact of such payments on the profitability of the transactions.

In the first nine months of 2013, 52.3 percent of all up-to congestion transactions were profitable.[43]

The MMU calculated the up-to congestion transactions that would have remained if operating reserve charges had been applied and the other identified quantifiable recommendations had been implemented. It was assumed that up-to congestion transactions would have maintained the same shares of profitable and unprofitable transactions after paying operating reserve charges as when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, 66.0 percent of all up-to congestion transactions would have been made. Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserve charges and the impact on other participants who pay those charges would have been significant.[44]

The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. Up-to congestion transactions would have paid an average rate between $0.311 and $0.407 per MWh in the first nine months of 2013 if the MMU's recommendations regarding operating reserves had been in place.[45]

Quantifiable Recommendations Impact

The MMU calculated the impact that all quantifiable recommendations would have had on the operating reserve rates paid by participants in the RTO, Eastern and Western Region. For reasons of confidentiality, these impacts cannot be disaggregated by issue. Five recommendations have been aggregated in this analysis: reallocation of operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts; reallocation of no load and startup costs of units providing reactive services; implementation of the proposed changes to lost opportunity cost calculations; elimination of internal bilateral transactions from the deviations calculation; and the allocation of operating reserve charges to up-to congestion transactions.

Table 4-38 shows the combined impact that these recommendations would have had on all operating reserve rates for the first nine months of 2013. The reduction in the rates is due to a decrease of 44.5 percent of the credits used to calculate these rates and a weighted average increase of 643.1 percent in the denominator used to calculate these rates.[46]

Table 4-38 MMU Recommendations Impact on Operating Reserve Rates: January through September 2013

	Current Rates ($/MWh)	Proposed Rates ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.086	0.029	(0.056)	(65.7%)
RTO Reliability	0.052	0.035	(0.016)	(31.7%)
East Reliability	0.031	0.031	(0.000)	(0.0%)
West Reliability	0.004	0.004	0.000	0.0%
RTO Deviations	0.886	0.060	(0.825)	(93.2%)
East Deviations	2.193	0.059	(2.135)	(97.3%)
West Deviations	0.118	0.012	(0.107)	(90.0%)
Lost Opportunity Cost	0.861	0.065	(0.796)	(92.4%)
Canceled Resources	0.001	0.000	(0.001)	(89.7%)

42 See "Quantifiable Recommendations Impact" on "Operating Reserve Issues" for the impact of this and other Operating Reserve recommendations.
43 An up-to congestion transaction profitability is based on its market value (difference between the day-ahead and real-time value) net of PJM and MMU administrative charges.
44 See "Quantifiable Recommendations Impact" on "Operating Reserve Issues" for the impact of this and other Operating Reserve recommendations.
45 The range of operating reserve rates paid by up-to congestion transactions depends on the location of the transactions' source and sink.
46 The weighted average was calculated based on the total charges by rate.

Table 4-39 shows the operating reserve cost of a 1 MW transaction had these recommendations been implemented in the first nine months of 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.218 per MWh, $3.564 per MWh or 94.2 percent less than the actual average rate paid. An up-to congestion transactions sourced in the Eastern Region and sinking at the Western Region would have been charged an average rate of $0.359 per MWh. Table 4-39 illustrates the current and proposed averages operating reserve rates for all transactions.

Table 4-39 Current and Proposed Average Operating Reserve Rate by Transaction: January through September 2013

		Rates Charged ($/MWh)		
	Transaction	Current	Proposed	Change
East	INC	3.663	0.189	(3.474)
	DEC	3.782	0.218	(3.564)
	DA Load	0.119	0.028	(0.090)
	RT Load	0.076	0.058	(0.018)
	Deviation	3.663	0.189	(3.474)
West	INC	1.726	0.141	(1.584)
	DEC	1.844	0.170	(1.675)
	DA Load	0.119	0.028	(0.090)
	RT Load	0.053	0.035	(0.018)
	Deviation	1.726	0.141	(1.584)
UTC	East to East	NA	0.407	
	West to West	NA	0.311	
	East to/from West	NA	0.359	

Confidentiality of Operating Reserves Information

PJM rules require all data posted publicly by PJM or the MMU to comply with existing confidentiality rules. Current confidentiality rules do not appear to allow posting data containing three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[47]

Operating reserves are out of market, non-transparent payments made to resources operating on the behalf of PJM to provide transmission constraint relief or other reliability services. Operating reserve charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons and locations of these payments, making it difficult for other participants to compete with the units receiving operating reserve payments. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of operating reserves information does exactly the opposite. There is no market in operating reserves and the absence of relevant information creates a very effective barrier to entry. The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of information regarding the reasons for operating reserve payments in the PJM region. This information would include the publication of operating reserve information by zone, by owner and by unit.

47 See "Manual 33 Administrative Services for the PJM Interconnection Operating Agreement," Revision 9 (July 22, 2012), Market Data Posting.

Capacity Market

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

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first nine months of calendar year 2013, 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 and the definition of DR which permits inferior products to substitute for capacity.

Overview

RPM Capacity Market

Market Design

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

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second,

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 *2013 Quarterly State of the Market Report for PJM*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
5 See 126 FERC ¶ 61,275 (2009) at P 86.

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. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand-side resources and Energy Efficiency resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During the period January 1 through September 30, 2013, PJM installed capacity increased 3,073.8 MW or 1.7 percent from 182,011.1 MW on January 1 to 185,084.9 MW on September 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 September 30, 2013, 41.9 percent was coal; 28.9 percent was gas; 17.9 percent was nuclear; 6.1 percent was oil; 4.4 percent was hydroelectric; 0.4 percent was solid waste; 0.5 percent was wind, and 0.0 percent was solar.
- **Market Concentration.** In the 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test. The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[9,10,11]
- **Imports and Exports.** Of the 7,493.7 MW of imports offered in the 2016/2017 RPM Base Residual Auction, 7,482.7 MW cleared. Of the cleared imports, 4,723.1 MW (63.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 8,490.0 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (3,193.8 MW).

Market Conduct

- **2014/2015 RPM Second Incremental Auction.** Of the 221 generation resources which submitted offers, unit-specific offer caps were calculated for six generation resources (2.7 percent). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps

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 See OATT Attachment DD § 6.5.
10 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.
11 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First Incremental Auction were conducted in the third quarter of 2013. In the 2014/2015 RPM Second Incremental Auction, the RTO clearing price for Annual Resources was $25.00 per MW-day. The weighted average capacity price for the 2014/2015 Delivery Year is $127.74, including all RPM Auctions for the 2014/2015 Delivery Year held through the first nine months of 2013. In the 2015/2016 First Incremental Auction, the RTO clearing price for Annual Resources was $43.00 per MW-day. The weighted average capacity price for the 2015/2016 Delivery Year is $160.03, including all RPM Auctions for the 2015/2016 Delivery Year held through the first nine months of 2013.
- The delivery year weighted average capacity price was $75.08 per MW-day in 2012/2013 and $116.55 per MW-day in 2013/2014.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for January through September was 8.0 percent, an increase from the 7.5 percent average PJM EFORd for 2012.[12]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for January through September was 84.2 percent, a slight increase from the 84.1 percent PJM aggregate equivalent availability factor for 2012.
- **Outages Deemed Outside Management Control (OMC).** In the first nine months of 2013, 34.3 percent of forced outages were classified as OMC outages. 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.

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 nine months of 2013. 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 nine months of 2013.[13]

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[14,15,16,17] In 2012, and 2013, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

12 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM Generator Availability Data Systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM. Data is for the twelve months ending December 31 or the nine months ending September 30, as downloaded from the PJM GADS database on October 22, 2013. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

13 For more complete conclusions, see *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market."

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

15 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).

16 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).

17 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).

Table 5-2 RPM related MMU reports, 2012 through September, 2013

Date	Name
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11-2875-003 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf
February 15, 2012	RPM-ACR and RPM Must Offer Obligation FAQs http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11-2871-000, -001 and -002, EL11-20-000 and -001 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf
April 9, 2012	Analysis of the 2014/2015 RPM Base Residual Auction www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf
May 1, 2012	IMM Complaint and Request for Fast Track Treatment and Shortened Comment Period re Complaint v. Unnamed Participant No. EL12-63 www.monitoringanalytics.com/report/Report/2012/IMM_Complaint_and_Fast_Track_Treatment_and_Shortened_Comment_Period_EL12-63-000_20120501.pdf
May 17, 2012	IMM Notice of Withdrawal re Complaint v. Unnamed Participant No. EL12-63 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Notice_of_Withdrawal_EL12-63-000_20120517.pdf
July 3, 2012	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligation for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120703.pdf
August 10, 2012	IMM Comments re Capacity Portability AD12-16 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_AD12-16_20120810.pdf
August 20, 2012	IMM and PJM Capacity White Papers on OPSI Issues http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf
August 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120829.pdf
November 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20121129.pdf
December 11, 2012	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf
March 29, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130329.pdf
April 19, 2013	IMM Answer and Motion for Leave to Answer re: MOPR No. ER13-535-001 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_ER13-535-001_20130419.pdf
June 19, 2013	Unit Specific MOPR Review Modeling Assumptions http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Unit_Specific_MOPR_Review_Modeling_Assumptions_20130619.pdf
June 20, 2013	Capacity Deliverability, Docket No. AD12-16 http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_FERC_Capacity_Deliverability_20130620.pdf
June 28, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130628.pdf
July 23, 2013	Analysis of Replacement Capacity for RPM Commitments http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Replacement_Capacity_Activity_Rev_20130723.pdf
August 30, 2013	RPM Unit-Specific Offer Cap Review Process http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Unit-Specific_Offer_Cap_Review_Process_20130830.pdf
September 3, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130903.pdf
September 13, 2013	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf
September 13, 2013	IMM Answer and Motion for Leave to Answer re RPM BRA Deadline Changes No. ER13-2140 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_ER13-2140_20130913.pdf
September 24, 2013	Analysis of the 2015/2016 RPM Base Residual Auction Report http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf

Installed Capacity

On January 1, 2013, PJM installed capacity was 182,011.1 MW (Table 5-3).[18] Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 185,084.9 MW on September 30, 2013, an increase of 3,073.8 MW or 1.7 percent over the January 1 level.[19,20] The 3,073.8 MW increase was the result of the integration of the East Kentucky Power Cooperative (EKPC) Zone (2,680.0 MW), new or reactivated generation (276.2 MW), an increase in imports (594.1 MW) capacity modifications (361.3 MW), and a decrease in exports (127.1 MW), offset by deactivations (687.0 MW) and derates (277.9 MW).

At the beginning of the new delivery year on June 1, 2013, PJM installed capacity was 185,567.9 MW, an increase of 3,531.6 MW or 1.9 percent over the May 31 level.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2013

	1-Jan-13		31-May-13		1-Jun-13		30-Sep-13	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,989.2	41.7%	76,055.6	41.8%	77,981.5	42.0%	77,496.7	41.9%
Gas	52,003.2	28.6%	52,106.1	28.6%	53,420.2	28.8%	53,425.9	28.9%
Hydroelectric	7,879.8	4.3%	7,880.4	4.3%	8,091.4	4.4%	8,106.7	4.4%
Nuclear	33,024.0	18.1%	33,024.0	18.1%	33,072.8	17.8%	33,076.9	17.9%
Oil	11,531.2	6.3%	11,361.2	6.2%	11,339.5	6.1%	11,314.2	6.1%
Solar	47.0	0.0%	47.0	0.0%	80.7	0.0%	82.7	0.0%
Solid waste	757.1	0.4%	756.4	0.4%	709.4	0.4%	709.4	0.4%
Wind	779.6	0.4%	805.6	0.4%	872.4	0.5%	872.4	0.5%
Total	182,011.1	100.0%	182,036.3	100.0%	185,567.9	100.0%	185,084.9	100.0%

18 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.
19 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.
20 Wind resources accounted for 872.4 MW of installed capacity in PJM on September 30, 2013. 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.

Table 5-4 Generation capacity changes: 2007/2008 through 2012/2013

	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)
Total		6,486.4	409.1	4,223.0	18,109.0	2,134.7	(2,641.9)	9,826.7	2,268.9	21,908.5

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.[21] In the third quarter of 2013, a Second Incremental Auction was held in July for the 2014/2015 Delivery Year, and a First Incremental Auction was held in September for the 2015/2016 Delivery Year.

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2012/2013 Delivery Year. The 21,908.5 MW increase was the result of new Generation Capacity Resources (6,486.4 MW), reactivated Generation Capacity Resources (409.1 MW), uprates (4,223.0 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (2,134.7 MW), a net decrease in capacity exports (2,641.9 MW), offset by deactivations (9,826.7 MW) and derates (2,268.9 MW).

In the 2014/2015 RPM Second Incremental Auction, 2,909.5 MW cleared of the 6,038.8 MW of participant sell offers. In the 2015/2016 RPM First Incremental Auction, 4,171.5 MW cleared of the 6,773.2 MW of participant sell offers. Effective with the 2012/2013 delivery year, PJM sell offers and buys bids are submitted in RPM Incremental Auctions as a result of changes in the RTO and LDA reliability requirements and the procurement of the Short-Term Resource Procurement Target. In the 2014/2015 RPM Second Incremental Auction, 1,635.3 MW cleared of the 2,039.8 MW of PJM sell offers for the RTO. In the 2015/2016 RPM Second Incremental Auction, 1,876.0 MW cleared of the 2,155.1 MW of PJM sell offers for the RTO.

Demand

In the 2014/2015 RPM Second Incremental Auction, 4,476.4 MW cleared of the 11,133.2 MW of participant buy bids, and 68.4 MW cleared of the 143.0 MW of PJM buy bids for the RTO. In the 2015/2016 RPM First Incremental Auction, 5,987.4 MW cleared of the 21,304.7 MW of participant buy bids, and 60.1 MW cleared of the 60.1 MW of PJM buy bids for the RTO. Participant buy bids are submitted to cover commitment and compliance shortfalls or because participants wanted to purchase additional capacity.

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

Market Concentration

Auction Market Structure

As shown in Table 5-5, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test in the 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First Incremental Auction.[22] The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[23,24,25]

Table 5-5 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.

Table 5-5 RSI results: 2013/2014 through 2016/2017 RPM Auctions[26]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2013/2014 BRA				
RTO	0.80	0.59	87	87
MAAC/SWMAAC	0.42	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.25	0.00	2	2
Pepco	0.00	0.00	1	1
2013/2014 First Incremental Auction				
RTO/MAAC	0.24	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.34	0.00	3	3
SWMAAC/Pepco	0.00	0.00	0	0
2013/2014 Second Incremental Auction				
RTO	0.44	0.27	32	32
MAAC/SWMAAC/Pepco	0.00	0.00	0	0
EMAAC/PSEG/PSEG North/DPL South	0.00	0.00	0	0
2013/2014 Third Incremental Auction				
RTO	0.60	0.38	60	60
MAAC/SWMAAC/Pepco	0.01	0.02	4	4
EMAAC/PSEG/PSEG North/DPL South	0.38	0.22	7	7
2014/2015 BRA				
RTO	0.76	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.40	1.03	7	0
PSEG North	0.00	0.00	1	1
2014/2015 First Incremental Auction				
RTO	0.45	0.14	36	36
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.00	0.00	1	1
PSEG North	0.00	0.00	1	1
2014/2015 Second Incremental Auction				
RTO	0.71	0.42	40	40
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.40	0.01	4	4
PSEG North	0.00	0.00	1	1
2015/2016 BRA				
RTO	0.75	0.57	99	99
MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco	0.49	0.63	12	12
ATSI	0.01	0.00	3	3
2015/2016 First Incremental Auction				
RTO	0.70	0.61	43	43
MAAC/EMAAC/SWMAAC/DPL South/Pepco	0.15	0.09	5	5
PSEG/PSEG North	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 BRA				
RTO	0.78	0.59	110	110
MAAC/EMAAC/SWMAAC/DPL South/Pepco	0.56	0.38	6	6
PSEG/PSEG North	0.00	0.00	1	1
ATSI/ATSI Cleveland	0.00	0.00	1	1

22 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
23 See OATT Attachment DD § 6.5.
24 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.
25 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

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

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[27] 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."[28] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

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

27 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.
28 OATT Attachment DD § 5.10 (a) (ii).

Figure 5-1 Map of PJM Locational Deliverability Areas

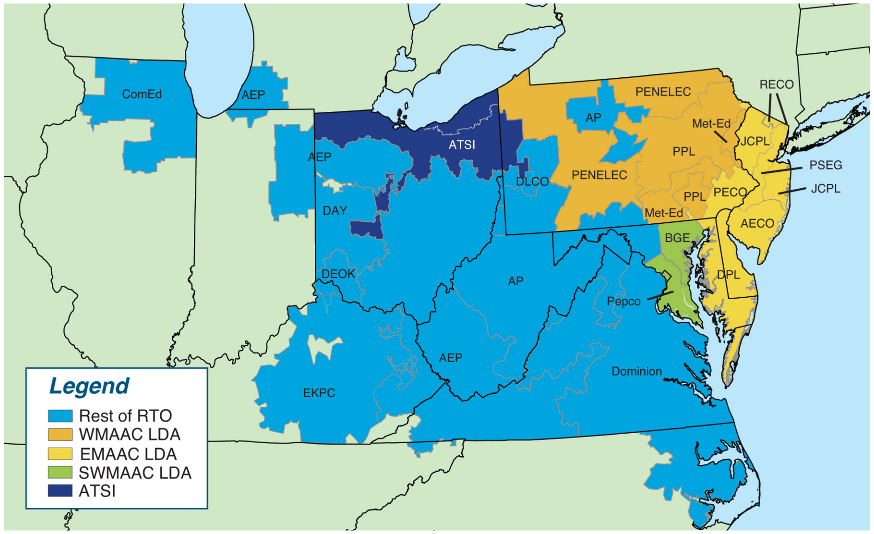


Figure 5-2 Map of PJM RPM EMAAC subzonal LDAs

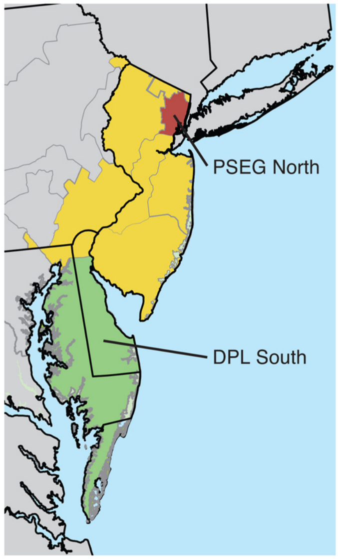
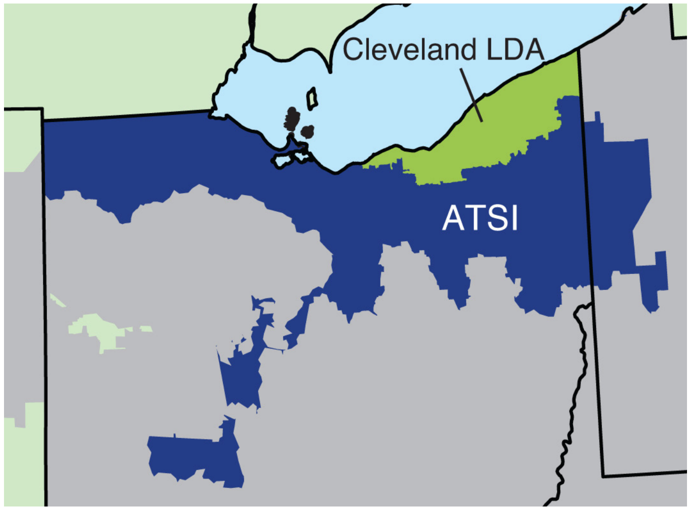


Figure 5-3 Map of PJM RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[29] As shown in Table 5-6, a total of 7,482.7 MW of imports cleared in the 2016/2017 RPM Base Residual Auction. Of these cleared imports, 4,723.1 MW (63.1 percent) were from MISO.

Table 5-6 RPM imports: 2007/2008 through 2016/2017 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7

Demand-Side Resources

As shown in Table 5-7 and Table 5-9, capacity in the RPM load management programs was 8,490.0 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (3,193.8 MW). Table 5-8 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

29 OATT Attachment DD § 5.6.6(b).

Table 5-7 RPM load management statistics by LDA: June 1, 2012 to June 1, 2016[30,31,32]

	UCAP (MW)									
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland
DR cleared	8,740.9	5,193.6	1,971.8	1,794.4	71.0	517.8	97.9			
EE cleared	666.1	253.6	48.1	160.1	0.0	15.9	7.8			
DR net replacements	(2,253.6)	(1,848.6)	(761.5)	(645.5)	(30.6)	(182.9)	10.1			
EE net replacements	(34.9)	(32.4)	(16.2)	(16.5)	0.0	(3.0)	(1.0)			
RPM load management @ 01-Jun-12	7,118.5	3,566.2	1,242.2	1,292.5	40.4	347.8	114.8			
DR cleared	10,779.6	6,466.6	2,735.7	1,788.8	155.4	1,185.0	534.8	661.9		
EE cleared	904.2	289.9	65.2	149.5	10.7	26.2	9.4	72.7		
DR net replacements	(3,318.8)	(3,016.9)	(1,434.3)	(745.7)	(53.3)	(819.7)	(388.6)	(272.4)		
EE net replacements	125.0	121.8	(11.1)	124.2	2.2	(2.1)	1.4	4.8		
RPM load management @ 01-Jun-13	8,490.0	3,861.4	1,355.5	1,316.8	115.0	389.4	157.0	467.0		
DR cleared	14,401.9	7,343.9	2,939.5	2,253.9	220.9	989.7	468.2	912.1		
EE cleared	1,021.9	291.9	37.3	169.8	8.1	17.0	8.2	51.4		
DR net replacements	(5.9)	(5.4)	(2.4)	(0.3)	0.0	(0.6)	0.0	0.0		
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
RPM load management @ 01-Jun-14	15,417.9	7,630.4	2,974.4	2,423.4	229.0	1,006.1	476.4	963.5		
DR cleared	14,922.1	6,692.2	2,631.3	2,009.1	86.3	797.0	263.3	867.4	1,763.7	
EE cleared	1,009.9	241.8	42.2	159.4	0.0	10.7	3.1	55.8	81.9	
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-15	15,932.0	6,934.0	2,673.5	2,168.5	86.3	807.7	266.4	923.2	1,845.6	
DR cleared	12,408.1	5,350.2	2,006.4	1,600.5	105.7	630.7	226.6	663.9	1,811.9	468.7
EE cleared	1,117.3	310.1	51.2	208.4	0.6	11.9	3.1	83.5	196.6	52.6
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-16	13,525.4	5,660.3	2,057.6	1,808.9	106.3	642.6	229.7	747.4	2,008.5	521.3

30 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.

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

32 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 are associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

Table 5-8 RPM load management cleared capacity and ILR: 2007/2008 through 2016/2017[33,34]

	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	13,835.5	14,401.9	983.2	1,021.9	0.0	0.0
2015/2016	14,358.3	14,922.1	973.0	1,009.9	0.0	0.0
2016/2017	11,918.7	12,408.1	1,074.7	1,117.3	0.0	0.0

Table 5-9 RPM load management statistics: June 1, 2007 to June 1, 2016[35,36]

	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	14,818.7	15,423.8	(5.7)	(5.9)	0.0	0.0	14,813.0	15,417.9
01-Jun-15	15,331.3	15,932.0	0.0	0.0	0.0	0.0	15,331.3	15,932.0
01-Jun-16	12,993.4	13,525.4	0.0	0.0	0.0	0.0	12,993.4	13,525.4

33 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.

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

35 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.

36 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 are associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to Capacity Resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[37,38,39]

37 See OATT Attachment DD § 6.5.

38 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.

39 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Table 5-10 ACR statistics: Auctions conducted in third quarter, 2013

	2014/2015 Second Incremental Auction		2015/2016 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	66	29.9%	24	18.3%
ACR data input (APIR)	5	2.3%	16	12.2%
ACR data input (non-APIR)	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	4	3.1%
Default ACR and opportunity cost	1	0.5%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	1	0.8%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	5	2.3%	3	2.3%
Price takers	144	65.2%	83	63.4%
Total Generation Capacity Resources offered	221	100.0%	131	100.0%

2014/2015 RPM Second Incremental Auction

As shown in Table 5-10, 221 generation resources submitted offers in the 2014/2015RPM Second Incremental Auction. Unit-specific offer caps were calculated for six generation resources (2.7 percent), including five generation resources (2.3 percent) with an Avoidable Project Investment Recovery Rate (APIR). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 (30.3 percent) were based on the technology specific default (proxy) ACR values. Of the 221 generation resources, five Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 144 generation resources were price takers (65.2 percent). Market power mitigation was applied to the sell offers for two generation resources.

2015/2016 RPM First Incremental Auction

As shown in Table 5-10, 131 generation resources submitted offers in the 2015/2016 RPM First Incremental Auction. Unit-specific offer caps were calculated for 20 generation resources (15.3 percent), including 16 generation resources with an Avoidable Project Investment Recovery Rate (APIR). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 (19.1 percent) were based on the technology specific default (proxy) ACR values. Of the 221 generation resources, three Planned Generation Capacity Resources had uncapped offers (2.3 percent), one generation resource had an uncapped planned uprate along with a default ACR based offer cap for the existing portion (0.8 percent), while the remaining 83 generation resources were price takers (63.4 percent). Market power mitigation was applied to the sell offer for one generation resource.

Market Performance[40]

Figure 5-4 presents cleared MW weighted average capacity market prices on a delivery year basis for the entire history of the PJM capacity markets. Table 5-11 shows RPM clearing prices for all RPM Auctions held through the first nine months of 2013.

Figure 5-5 illustrates the RPM cleared MW weighted average prices for each LDA for the current delivery year and all results for future delivery years that have been held through the first nine months of 2013.

Table 5-12 shows RPM revenue by resource type for all RPM Auctions held through the first nine months of 2013 with $2.1 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices.

Table 5-13 shows RPM revenue by calendar year for all RPM Auctions held through the first nine months of 2013.

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

Table 5-11 Capacity prices: 2007/2008 through 2016/2017 RPM Auctions

		RPM Clearing Price ($ per MW-day)									
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54	
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$148.80	$210.11	
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$191.32	$237.33	
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	$174.29	
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$139.73	$185.00	$133.37	
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23

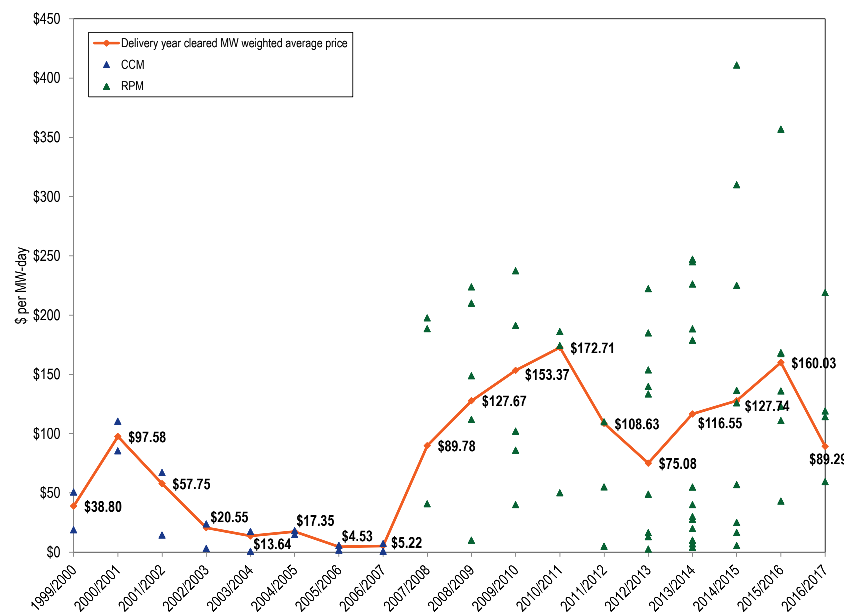
Table 5-12 RPM revenue by type: 2007/2008 through 2016/2017[41,42]

				Coal		Gas		Hydroelectric		Nuclear		Oil		Solar		Solid waste		Wind		
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/ repower/ reactivated	Existing	New/ repower/ reactivated	Existing	New/ repower/ reactivated	Existing	New/ repower/ reactivated	Existing	New/ repower/ reactivated	Existing	New/repower/ reactivated	Total revenue
2007/2008	$5,537,085	$0	$22,225,980	$1,022,372,301	$0	$1,458,989,006	$3,472,667	$209,490,444	$0	$996,085,233	$0	$502,172,373	$0	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$35,349,116	$0	$60,918,903	$1,844,120,476	$0	$1,910,349,518	$9,751,112	$287,850,403	$0	$1,322,601,837	$0	$572,259,505	$4,837,523	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$65,762,003	$0	$56,517,793	$2,417,576,805	$1,854,781	$2,275,446,414	$30,168,831	$364,742,517	$0	$1,517,723,628	$0	$715,618,319	$5,676,582	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$60,235,796	$0	$106,046,871	$2,662,434,386	$3,168,069	$2,586,971,699	$58,065,964	$442,429,815	$0	$1,799,258,125	$0	$668,505,533	$4,339,539	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$55,795,785	$139,812	$185,421,273	$1,595,707,479	$28,330,047	$1,607,317,731	$98,448,693	$278,529,660	$0	$1,079,386,338	$0	$368,084,004	$967,887	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,016,194,603	$7,568,127	$1,079,413,451	$76,633,409	$179,117,975	$11,397	$762,719,550	$0	$423,957,756	$2,772,987	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,745,438,458	$12,950,135	$1,846,432,716	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0	$689,864,789	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$672,042,592	$41,075,583	$131,766,080	$1,915,786,864	$57,078,818	$1,977,669,867	$188,665,243	$329,051,834	$6,591,114	$1,460,153,171	$0	$473,230,023	$4,101,872	$0	$3,525,901	$34,529,651	$1,694,126	$1,524,551	$32,682,583	$7,331,169,873
2015/2016	$882,512,351	$55,664,349	$190,102,852	$2,779,290,152	$63,163,731	$2,475,378,226	$529,577,871	$385,193,684	$14,880,302	$1,849,263,911	$0	$566,555,231	$5,243,967	$0	$4,526,101	$35,716,918	$4,258,208	$1,829,269	$41,406,297	$9,884,563,419
2016/2017	$437,607,477	$35,346,456	$157,012,514	$1,259,270,875	$42,487,007	$1,461,069,582	$498,909,311	$218,627,999	$10,031,353	$1,002,422,494	$0	$327,077,318	$4,026,475	$0	$4,868,047	$28,668,947	$3,780,862	$1,144,873	$20,886,259	$5,513,237,849

Table 5-13 RPM revenue by calendar year: 2007 through 2017[43]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$123.11	158,258.0	365	$7,111,333,803
2015	$146.67	164,609.3	365	$8,812,393,764
2016	$118.67	168,936.9	366	$7,337,483,492
2017	$89.29	169,159.7	151	$2,280,818,946

Figure 5-4 History of PJM capacity prices: 1999/2000 through 2016/2017[44]



41 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

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

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

44 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2016/2017 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 Delivery Year and forward, only the prices for Annual Resources are plotted.

Figure 5-5 Map of RPM capacity prices: 2013/2014 through 2016/2017

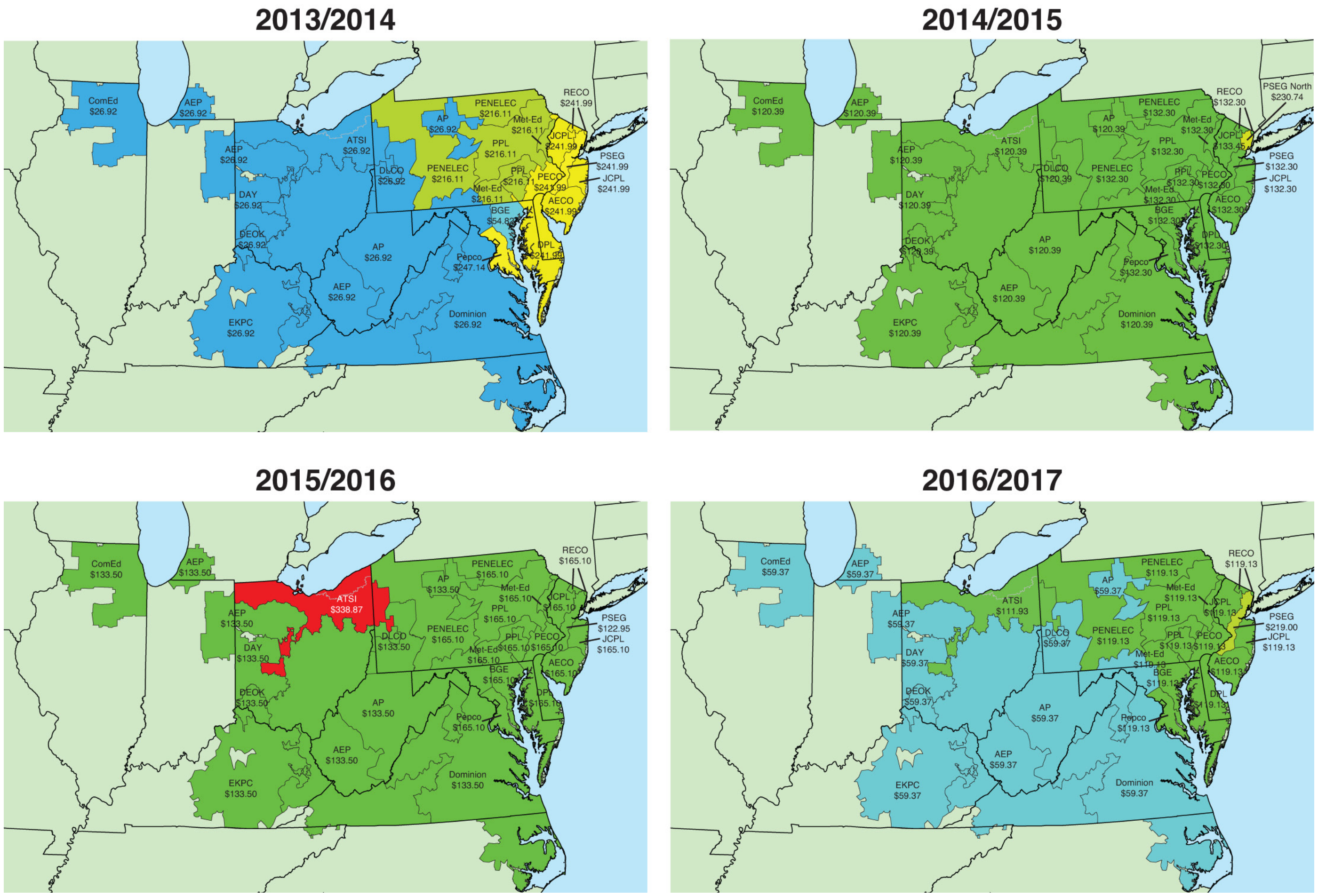


Table 5-14 shows the RPM annual charges to load. For the 2013/2014 planning year, RPM annual charges to load total approximately $6.7 billion.

Table 5-14 RPM cost to load: 2012/2013 through 2016/2017 RPM Auctions[45,46,47]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2012/2013			
Rest of RTO	$16.74	65,495.4	$400,296,161
Rest of MAAC	$133.42	30,107.9	$1,466,181,230
Rest of EMAAC	$143.06	19,954.6	$1,041,932,095
DPL	$171.27	4,523.9	$282,806,394
PSEG	$157.73	11,645.3	$670,441,158
Total		131,727.1	$3,861,657,038
2013/2014			
Rest of RTO	$28.45	80,012.1	$830,802,258
Rest of MAAC	$232.55	14,623.8	$1,241,276,219
EMAAC	$248.30	36,094.7	$3,271,227,460
Rest of SWMAAC	$231.58	7,925.5	$669,900,300
Pepco	$244.94	7,525.2	$672,777,842
Total		146,181.3	$6,685,984,079
2014/2015			
Rest of RTO	$129.28	81,309.3	$3,836,841,975
Rest of MAAC	$138.36	30,331.6	$1,531,762,816
Rest of EMAAC	$138.36	20,118.8	$1,016,059,638
DPL	$146.14	4,593.1	$244,995,176
PSEG	$171.46	11,669.9	$730,342,563
Total		148,022.7	$7,360,002,168
2015/2016			
Rest of RTO	$135.72	83,538.3	$4,149,635,361
Rest of MAAC	$166.40	55,889.0	$3,403,719,326
PSEG	$166.18	11,787.4	$716,915,782
ATSI	$295.97	14,786.2	$1,601,698,117
Total		166,000.8	$9,871,968,586
2016/2017			
Rest of RTO	$59.37	88,722.2	$1,922,615,128
Rest of MAAC	$118.89	57,413.6	$2,491,443,430
PSEG	$177.61	12,055.9	$781,575,871
ATSI	$90.54	15,121.1	$499,720,114
Total		173,312.9	$5,695,354,543

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

46 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.

47 Prior to the 2009/2010 Delivery Year, the Final UCAP Obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the Final UCAP Obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 Delivery Year, the Final UCAP Obligation is determined after the clearing of the final Incremental Auction. Prior to the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after the final Incremental Auction. The 2014/2015, 2015/2016, and 2016/2017 Net Load Prices are not finalized. The 2014/2015, 2015/2016, and 2016/2017 Obligation MW are not finalized.

Replacement Capacity

The IMM's review and analysis of replacement capacity activity is the issue source for the problem statement/issue charge which is currently being discussed in the PJM stakeholder process.[48,49] The IMM proposed a solution package at the Capacity Senior Task Force (CSTF) which includes increasing the Capacity Resource Deficiency Charge; modifying how PJM releases capacity in Incremental Auctions; defining the First and Second Incremental Auction as not mandatory and held due to increases in the Reliability Requirement exceeding certain thresholds; and adding a Market Seller Offer Cap option for First and Second Incremental Auctions, if held, of 1.0 times the Base Residual Auction clearing price. The IMM also recommends that the rules governing the requirement to be a physical resource are enforceed.[50]

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).[51]

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 nine months of 2013, nuclear units had a capacity factor of 93.8 percent, compared to 92.7 percent in the first nine months of 2012. Combined cycle units ran less often,

48 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf> (December 18, 2012).

49 The Replacement Capacity Issue Charge and Problem Statement were presented at the March 6, 2013 MIC meeting. See "Item 04B – Replacement Capacity Issue Charge," < http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-04b-replacement-capacity-issue-charge.ashx>.

50 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).

51 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.

decreasing from a percent capacity factor of 62.9 percent in the first nine months of 2012 to 52.9 in the first nine months of 2013. The capacity factor for steam units, which are primarily coal fired, increased from 45.5 percent in the first nine months of 2012 to 49.8 percent in the first nine months of 2013.

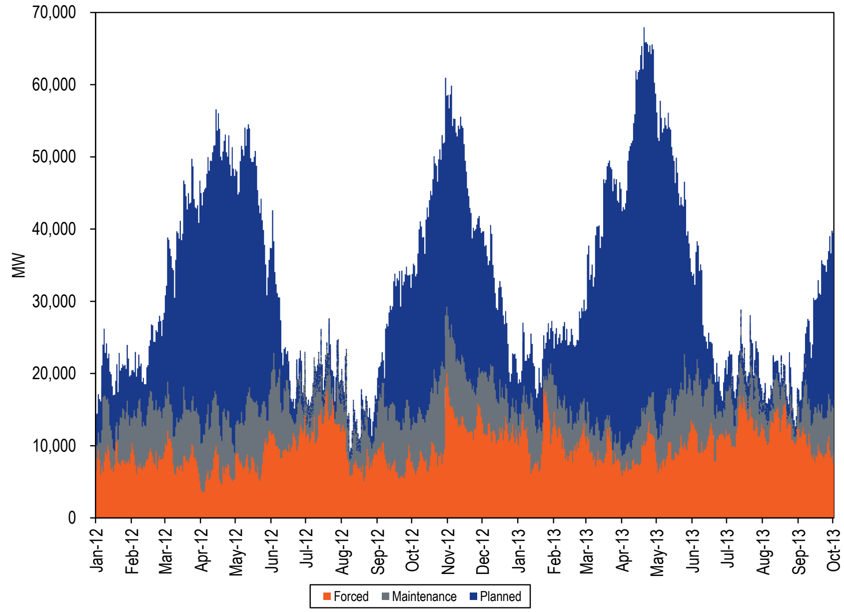
Table 5-15 PJM capacity factor (By unit type (GWh)): January through September 2012 and 2013[52,53]

	Jan-Sep 2012		Jan-Sep 2013	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.2	0.1%	0.4	0.2%
Combined Cycle	108,088.4	62.9%	90,466.4	52.9%
Combustion Turbine	7,273.8	3.7%	6,585.0	3.3%
Diesel	461.1	15.7%	451.8	16.2%
Diesel (Landfill gas)	913.4	41.2%	1,012.2	41.6%
Fuel Cell	5.7	76.5%	63.4	32.3%
Nuclear	205,503.9	92.7%	207,254.4	93.8%
Pumped Storage Hydro	5,097.0	14.1%	5,297.4	14.7%
Run of River Hydro	4,671.2	29.5%	5,847.2	36.5%
Solar	192.7	16.9%	288.4	17.7%
Steam	261,408.8	45.5%	273,138.1	49.8%
Wind	8,944.7	25.2%	10,379.3	24.9%
Total	602,560.9	47.8%	600,784.1	48.4%

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The amount of MW on outages varies throughout the year. For example, the MW on planned outages are generally highest in the spring and fall, as shown in Figure 5-6, due to restrictions on planned outages during the winter and summer. The effect of seasonal variation in outages can be seen in the monthly generator performance metrics in "Performance By Month."

Figure 5-6 PJM outages (MW): January 2012 to September 2013



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, EFOF, EPOF, and EMOF are shown in Figure 5-7. Metrics by unit type are shown in Table 5-16 through Table 5-19.

52 The capacity factors for wind and solar unit types described in this table are based on nameplate capacity values, and are calculated based on when the units come online.
53 The EKPC Transmission Zone was integrated on June 1, 2013 and is included in the January through September numbers for 2013.

Figure 5-7 PJM equivalent outage and availability factors: 2007 to 2013

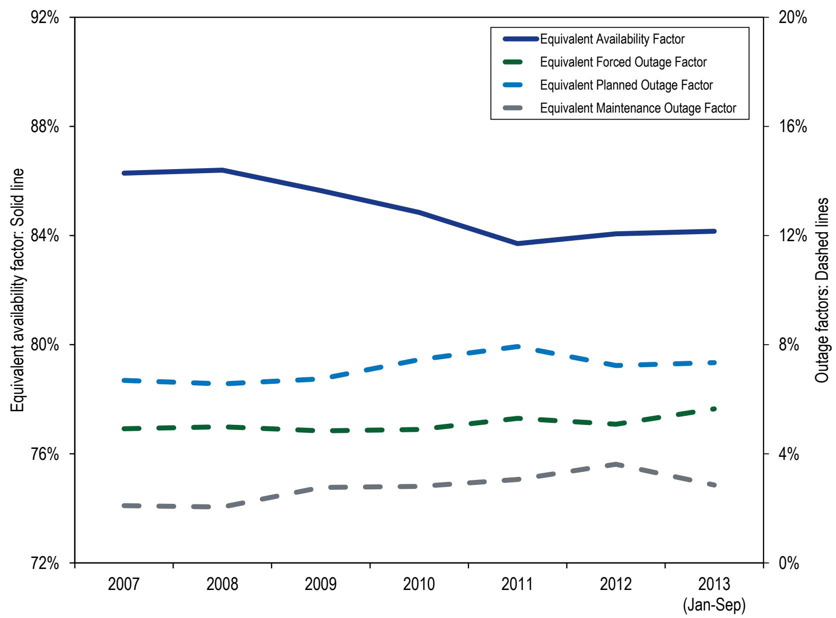


Table 5-16 EAF by unit type: 2007 through September 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	89.7%	90.2%	87.8%	85.9%	85.4%	85.4%	86.2%
Combustion Turbine	90.5%	91.1%	93.2%	93.1%	91.8%	92.4%	90.7%
Diesel	86.4%	87.8%	91.2%	94.1%	94.8%	92.5%	93.7%
Hydroelectric	90.1%	88.8%	86.9%	88.8%	84.6%	88.8%	89.6%
Nuclear	93.1%	92.3%	90.1%	91.8%	90.1%	91.1%	92.4%
Steam	81.3%	81.6%	80.9%	79.0%	78.2%	77.9%	77.4%
Total	86.3%	86.4%	85.6%	84.8%	83.7%	84.1%	84.2%

Table 5-17 EMOF by unit type: 2007 through September 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	2.0%	1.6%	3.0%	3.1%	2.4%	2.7%	2.6%
Combustion Turbine	2.5%	2.2%	2.3%	2.0%	2.4%	1.7%	1.6%
Diesel	1.8%	1.2%	1.2%	1.5%	2.0%	2.6%	1.4%
Hydroelectric	1.4%	2.1%	2.3%	1.9%	1.9%	2.1%	1.6%
Nuclear	0.3%	0.8%	0.6%	0.5%	1.2%	1.1%	0.8%
Steam	2.7%	2.6%	3.7%	3.9%	4.2%	5.6%	4.3%
Total	2.1%	2.1%	2.8%	2.8%	3.1%	3.6%	2.9%

Table 5-18 EPOF by unit type: 2007 through September 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	5.9%	6.0%	6.3%	8.2%	9.6%	8.3%	8.3%
Combustion Turbine	2.5%	4.0%	2.8%	3.0%	3.8%	3.2%	2.7%
Diesel	0.7%	1.1%	0.6%	0.5%	0.1%	0.7%	0.3%
Hydroelectric	7.2%	7.8%	8.6%	8.6%	11.8%	6.3%	6.8%
Nuclear	5.3%	5.1%	5.2%	5.4%	6.1%	6.4%	5.6%
Steam	8.6%	8.0%	8.6%	9.4%	9.2%	8.7%	9.5%
Total	6.7%	6.6%	6.7%	7.5%	7.9%	7.2%	7.3%

Table 5-19 EFOF by unit type: 2007 through June 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	2.3%	2.3%	2.9%	2.7%	2.6%	3.6%	2.8%
Combustion Turbine	4.5%	2.7%	1.6%	1.9%	2.0%	2.8%	5.1%
Diesel	11.2%	9.9%	7.0%	3.8%	3.2%	4.2%	4.6%
Hydroelectric	1.3%	1.3%	2.3%	0.7%	1.7%	2.8%	2.0%
Nuclear	1.3%	1.8%	4.1%	2.3%	2.6%	1.5%	1.2%
Steam	7.3%	7.9%	6.8%	7.7%	8.3%	7.8%	8.7%
Total	4.9%	5.0%	4.8%	4.9%	5.3%	5.1%	5.6%

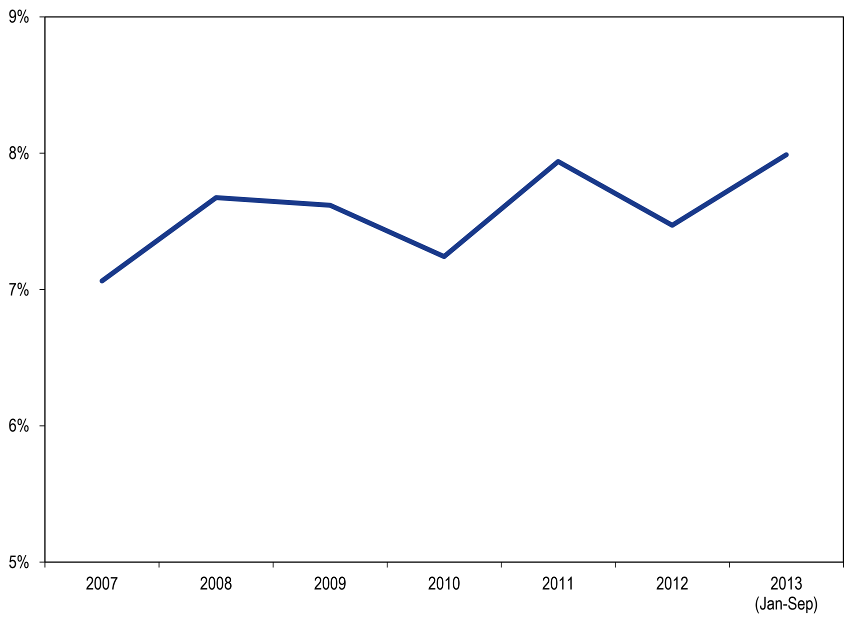
Generator Forced Outage Rates

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

Figure 5-8 shows the average EFORd since 2007 for all units in PJM.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2013



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

Table 5-20 shows the class average EFORd by unit type.

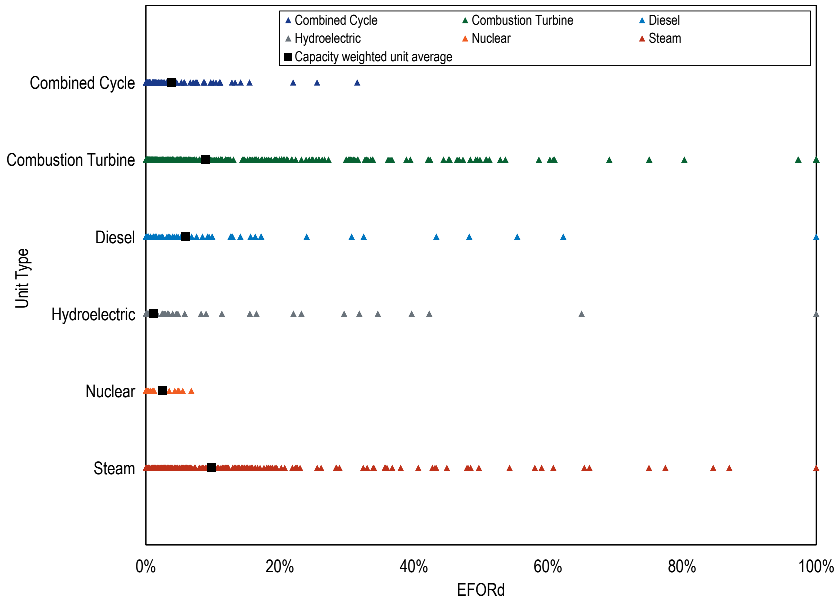
Table 5-20 PJM EFORd data for different unit types: 2007 through September 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	3.8%	3.9%	4.3%	3.9%	3.5%	4.3%	3.5%
Combustion Turbine	11.1%	11.1%	9.8%	8.9%	8.0%	8.2%	10.1%
Diesel	12.9%	11.2%	9.9%	5.9%	9.6%	5.5%	5.1%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.1%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.3%
Steam	9.2%	10.1%	9.4%	9.8%	11.3%	10.6%	11.6%
Total	7.1%	7.7%	7.6%	7.2%	7.9%	7.5%	8.0%

Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates within each unit type. The distribution of EFORd by unit type is shown in Figure 5-9. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Combustion turbine units had the greatest variance of EFORd, while nuclear units had the lowest variance in EFORd values in the first nine months of 2013.

Figure 5-9 PJM distribution of EFORd data by unit type: January through September 2013



Other Forced Outage Rate Metrics

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

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

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

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

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[55] 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.[56] 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 the NERC directive.

55 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>.

56 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>.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metric used in the Capacity Market.[57] That choice was made by PJM and can be modified without violating any NERC requirements.[58] It is possible to have an OMC outage under the NERC definition, which PJM does not define as OMC for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

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

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 5-21 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages account for 34.3 percent of all forced outages. The second-largest contributor to OMC outages, lack of fuel, was the cause in of 28.0 percent of OMC outages and 9.6 percent of all forced outages. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."

The largest contributor to OMC outages, hurricane, affected a number of large units in the early spring. Also contributing to hurricane outages were several units that have been on outage since the 2012 hurricane.

57 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.

58 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 5-21 OMC Outages: January through September 2013

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Hurricane	41.2%	14.1%
Lack of fuel	28.0%	9.6%
Flood	14.3%	4.9%
Transmission system problems other than catastrophes	5.2%	1.8%
Lightning	4.4%	1.5%
Other switchyard equipment external	1.5%	0.5%
Switchyard circuit breakers external	1.3%	0.5%
Transmission line	1.2%	0.4%
Other miscellaneous external problems	0.7%	0.2%
Transmission equipment beyond the 1st substation	0.5%	0.2%
Lack of water	0.5%	0.2%
Storms	0.4%	0.1%
Transmission equipment at the 1st substation	0.3%	0.1%
Frozen coal	0.1%	0.0%
Switchyard system protection devices	0.1%	0.0%
Switchyard transformers and associated cooling systems	0.1%	0.0%
Other fuel quality problems	0.1%	0.0%
Tornados	0.0%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Wet coal	0.0%	0.0%
Other catastrophe	0.0%	0.0%
Total	100.0%	34.3%

An outage is an outage, regardless of the cause. Lack of fuel is especially noteworthy because, even if the OMC concept were accepted, the lack of fuel reasons are not outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. These are economic issues within the control of management and the resultant tradeoffs should be reflected in actual forced outage rates rather than ignored by designation as OMC. It is significant that some OMC outages are classified as economic. Firm gas contracts could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage. If a particular unit or set of units have outages on a regular basis for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.[59]

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

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

The MMU recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage. The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market after appropriate notice.

All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that pending elimination of OMC outages, PJM review all requests for OMC carefully, develop a clear, transparent set of written public rules governing the designation of outages as OMC and post those guidelines. Any resultant OMC outages may be considered by PJM but should not be reflected in forced outage metrics which affect system planning or market payments to generating units.

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.

PJM EFOF was 5.6 percent in 2013. This means there was 5.6 percent lost availability because of forced outages. Table 5-22 shows that forced outages for boiler tube leaks, at 16.8 percent of the systemwide EFOF, were the largest single contributor to EFOF.

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

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.

Table 5-22 Contribution to EFOF by unit type by cause: January through September 2013

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	5.1%	0.0%	0.0%	0.0%	0.0%	21.4%	16.8%
Catastrophe	5.9%	56.0%	7.6%	1.4%	20.7%	4.6%	11.5%
Boiler Piping System	4.0%	0.0%	0.0%	0.0%	0.0%	6.2%	5.0%
Economic	0.9%	8.2%	4.9%	1.6%	0.0%	4.3%	4.4%
High Pressure Turbine	32.6%	0.0%	0.0%	0.0%	0.0%	3.2%	4.3%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	5.5%	4.2%
Feedwater System	0.7%	0.0%	0.0%	0.0%	6.4%	4.0%	3.4%
Electrical	1.7%	1.8%	6.4%	8.1%	6.1%	3.4%	3.2%
Miscellaneous (Steam Turbine)	3.1%	0.0%	0.0%	0.0%	0.1%	3.6%	2.9%
Boiler Fuel Supply from Bunkers to Boiler	0.1%	0.0%	0.0%	0.0%	0.0%	2.9%	2.3%
Controls	3.2%	5.6%	0.1%	0.6%	3.9%	1.0%	1.8%
Circulating Water Systems	2.1%	0.0%	0.0%	0.0%	6.8%	1.4%	1.4%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%	2.8%
Fuel Quality	0.0%	0.1%	4.4%	0.0%	0.0%	1.6%	1.2%
Stack Emission	0.3%	1.4%	0.6%	0.0%	0.0%	3.3%	2.7%
Miscellaneous (External)	5.1%	0.0%	0.5%	70.2%	0.1%	0.0%	1.2%
Boiler Internals and Structures	0.9%	0.0%	0.0%	0.0%	0.0%	1.5%	1.2%
Generator	1.7%	0.3%	5.6%	1.7%	22.0%	0.4%	1.2%
Reserve Shutdown	0.3%	2.7%	25.9%	0.8%	0.0%	4.1%	3.6%
All Other Causes	32.3%	24.0%	44.1%	15.6%	33.9%	24.1%	24.8%
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.[61] Lack of fuel that is considered Outside Management Control accounted for 81.0 percent of all economic reasons.

Table 5-23 Contributions to Economic Outages: January through September 2013

	Contribution to Economic Reasons
Lack of fuel (OMC)	81.0%
Lack of fuel (Non-OMC)	18.2%
Lack of water (Hydro)	0.5%
Fuel conservation	0.2%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.1%
Other economic problems	0.0%
Total	100.0%

61 The definitions of these outages are defined by NERC GADS.

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."[62] 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.

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.[63] 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

62 The definitions of these outages are defined by NERC GADS.
63 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

take 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.

Table 5-24 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for steam units and combustion turbine units.

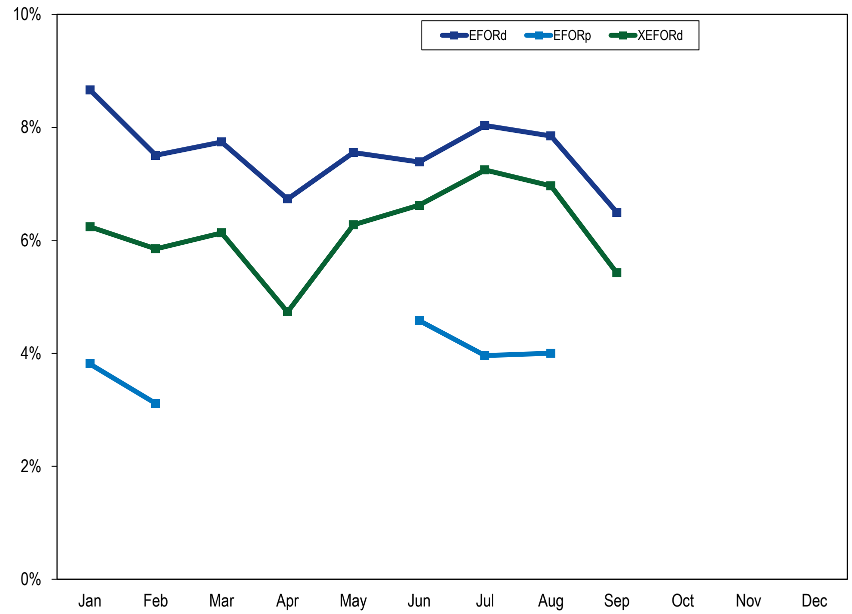
Table 5-24 PJM EFORd, XEFORd and EFORp data by unit type: January through September 2013[64]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.5%	3.2%	1.1%	0.4%	2.4%
Combustion Turbine	10.1%	6.3%	3.5%	3.9%	6.6%
Diesel	5.1%	4.6%	1.5%	0.5%	3.6%
Hydroelectric	3.1%	1.0%	0.9%	2.1%	2.2%
Nuclear	1.3%	1.0%	1.2%	0.3%	0.1%
Steam	11.6%	10.2%	6.4%	1.4%	5.2%
Total	8.0%	6.5%	4.0%	1.5%	4.0%

Performance By Month

On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 5-10, demonstrating that units had fewer outages during peak hours than would have been expected based on EFORd.

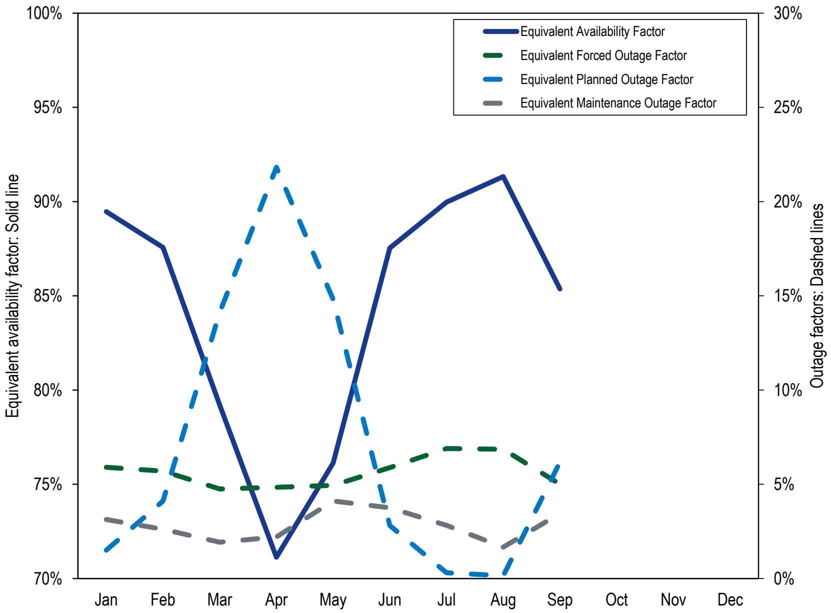
Figure 5-10 PJM EFORd, XEFORd and EFORp: January through September 2013



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

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

Figure 5-11 PJM monthly generator performance factors: January through September 2013



Demand Response (DR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Activity.** In the first nine months of 2013, total load reduction under the Economic Load Response Program decreased by 7,002 MWh compared to the same period in 2012, from 121,381 MWh in the first nine months of 2012 to 114,379 MWh in the first nine months of 2013, a six percent decrease. Total credits under the Economic Program decreased by $1,084,448, from $8,172,654 in the first nine months of 2012 to $7,088,205 in the same period of 2013, a 13 percent decrease. September credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day.

  The capacity market is the primary source of revenue to participants in PJM demand side programs. In the first nine months of 2013, Load Management (LM) Program revenue increased $33.8 million, or 12.8 percent, compared to the same period of 2012, from $263.6 million to $297.4 million in 2013.

  In the first nine months of 2013, Synchronized Reserve credits for demand side resources decreased by $1.9 million, or 54.2 percent, compared to the same period in 2012, from $3.6 million to $1.6 million in 2013.

- **Locational Dispatch of Demand-Side Resources.** PJM dispatches demand-side resources on a subzonal basis when appropriate, but only on a voluntary basis. Beginning with the 14/15 Delivery Year, demand resources will be dispatchable on a subzonal basis, defined by zip codes. More locational deployment of demand-side resources improves efficiency in a nodal market.

- **Load Management Product.** The load management product is currently defined as an emergency product. The load management product is an economic product and should be treated as an economic product in the PJM market design and in PJM dispatch. Demand resources should be called when the resources are required and prior to the declaration of an emergency. The MMU recommends that the DR program be classified as an economic program and not an emergency program.

- **Emergency Event Day Analysis.** Load management event rules allow over compliance to be reported when there is no actual over compliance. Settlement MWh are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero even if load actually increases. Considering all and only reported values, the observed load reduction of the five events in 2013 should have been 5,116.9 MW, rather than the 5,644.7 MW reported. Overall, compliance decreases from the reported 100.5 percent to 90.6 percent. This does not include locations that did not report their load during the emergency event days.

Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption. The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.

The MMU recommends that demand side measurement and verification be further modified to more accurately reflect compliance. Increases in load by load management resources during event hours should not be considered zero response or ignored, but should be included for reporting and determining compliance. Load management testing does not adequately reflect actual resource performance during event days. Testing should be initiated by PJM with limited warning to CSPs in order to more accurately reflect the conditions of an emergency event.[1] The MMU recommends that load management resources whose load drop method is designated as "Other" explicitly record the method of load drop.

The load management product is currently defined as an emergency product. In fact, the load management product is an economic product and it is treated as an economic product in the PJM capacity market design where it competes directly with generation capacity, affects market clearing prices and receives the market clearing price. The load management product should also be treated as an economic product in PJM dispatch meaning that demand resources should be called when the resources are required and prior to the declaration of an emergency. For these reasons, the MMU recommends that the DR program be classified as an economic program and not an emergency program.[2]

More locational deployment of Load Management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

1 For additional conclusions see the *2012 State of the Market Report for PJM*, Volume 2: Section 5, "Demand Response."
2 This issue is currently being discussed in the Capacity Senior Task Force (CSTF) with an expected resolution by summer 2014.

Along with the removal of load increases from compliance, non-reporting can cause an overstatement of load reductions of the reported load at a node. The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations. Negative event performance of a portfolio should be netted against the positive performance of other resources. Reported compliance should include those locations that increased load in addition to those that reduced load during an emergency event. The MMU also recommends that PJM adopt the ISO-NE metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to DR resources are based on actual metered data.[3]

PJM Demand Response Programs

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 6-1 provides an overview of the key features of PJM load response programs.[4]

Table 6-1 Overview of Demand Side Programs[5]

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
DR cleared in RPM;	DR cleared in RPM	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment.

3 ISO-NE requires that DR resource have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, Demand Response resources in ISO-NE must also be registered at a single node. See Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response."
4 For more detail on the historical development of PJM Load Response Programs see the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml>.
5 Prior to April 1, 2012, payment for the Economic Load Response Program was based on LMP minus the generation and transmission components of the retail rate.

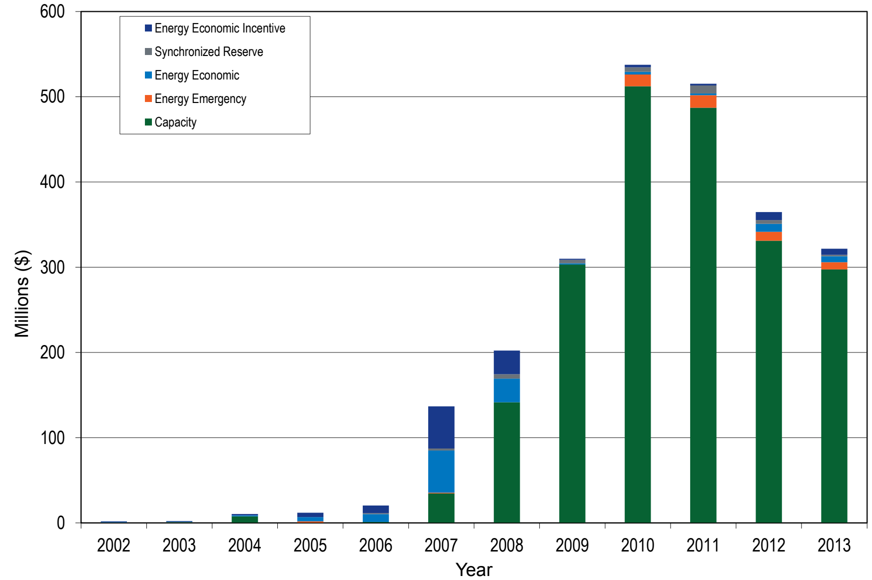
Participation in Demand Response Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM Economic Program, mandating payment of full LMP for dispatched demand resources. In the first nine months of 2013, in the Economic Program, participation decreased compared to the same period in 2012. There were fewer settlements submitted and fewer active participants in the first nine months of 2013 compared to the same period in 2012, and credits decreased. September credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day.

Figure 6-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through the first nine months of 2013. Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to demand side participants, representing 94.6 percent of all revenue received through demand response programs in the first nine months of 2013. In the first nine months of 2013, total credits under the Economic Program decreased by $1,084,448, from $8,172,654 in the first nine months of 2012 to $7,088,205 in the same period of 2013. This represents a 13 percent decrease in credits. The total MWh reductions decreased by seven percent for the first seven months of 2013 compared to the first seven months of 2012. In the first nine months of 2013, capacity revenue represents 94.6 percent of all revenue received by demand response providers, emergency energy revenue represented 2.7 percent, revenue from the economic program represented 2.3 percent and revenue from Synchronized Reserve represented 0.5 percent.

Capacity revenue increased by $33.8 million, or 12.8 percent, from $263.7 million to $297.4 million in the first nine months of 2013, primarily due to higher clearing prices in the RPM market for the 2013/2014 Delivery Year. Synchronized Reserve credits for demand side resources decreased by $1.9 million, from $3.6 million to $1.6 million in the first nine months 2013, due to lower clearing prices in the Synchronized Reserve market.

Figure 6-1 Demand Response revenue by market: 2002 through September 2013



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period 2010 through the first nine months of 2013. The average registered MW for the first nine months increased by 202 MW from 2,175 in 2012 to 2,377. Historically, registered MW have declined in June but have increased in August, which is likely the result of expirations and renewals. Registration in the Economic Program means that customers have been signed up and can participate if they choose. Although registrations decreased, total registered MW were higher by 1,815 MW in the first nine months of 2013 compared to the same period of 2012. The registered MW per registration increased in the first nine months of 2013 compared to the first nine months of 2012. The average number of active registrations was 1,150 in the first nine months of 2012 and 1,113 in the same period in 2013.

Table 6-2 Economic Program registrations on the last day of the month: 2010 through September 2013

	2010		2011		2012		2013	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,841	2,623	1,609	2,432	1,993	2,385	841	2,321
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,333
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,291
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,341
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,412
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,138
Jul	1,192	2,159	1,228	2,062	942	2,323	1,315	2,473
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,568
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,516
Oct	1,606	2,444	1,954	2,179	828	2,269		
Nov	1,605	2,444	1,988	2,255	824	2,267		
Dec	1,598	2,439	1,992	2,259	846	2,283		
Avg.	1,608	2,435	1,699	2,344	1,071	2,200	1,113	2,377

Total credits in Table 6-3 exclude incentive credits in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[6]

Table 6-3 Performance of PJM Economic Program participants excluding incentive credits: 2003 through September 2013

Year	Total MWh	Total Credits	$/MWh
2009 (Jan-Sep)	45,424	$1,160,957	$25.56
2010 (Jan-Sep)	58,280	$2,677,937	$45.95
2011 (Jan-Sep)	15,376	$1,943,507	$126.40
2012 (Jan-Sep)	120,070	$8,149,477	$67.87
2013 (Jan-Sep)	114,379	$7,088,205	$61.97

6 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate (recoverable charges), was charged to all LSEs in the zone of the load reduction. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

Figure 6-2 shows monthly economic program credits, excluding incentive credits, for 2009 through September 2013. Higher energy prices and FERC Order 745 increased incentives to participate during the first nine months of 2013. During the peak summer months of June through August, total Economic Demand Response credits decreased by $2,506,945 from $6,764,613 in June through August of 2012 to $4,257,946 in the same period of 2013. September 2013 data do not yet reflect complete economic program activity results as participants have up to 60 days to submit data for settlement.

Figure 6-2 Economic Program credits by month: 2009 through September 2013

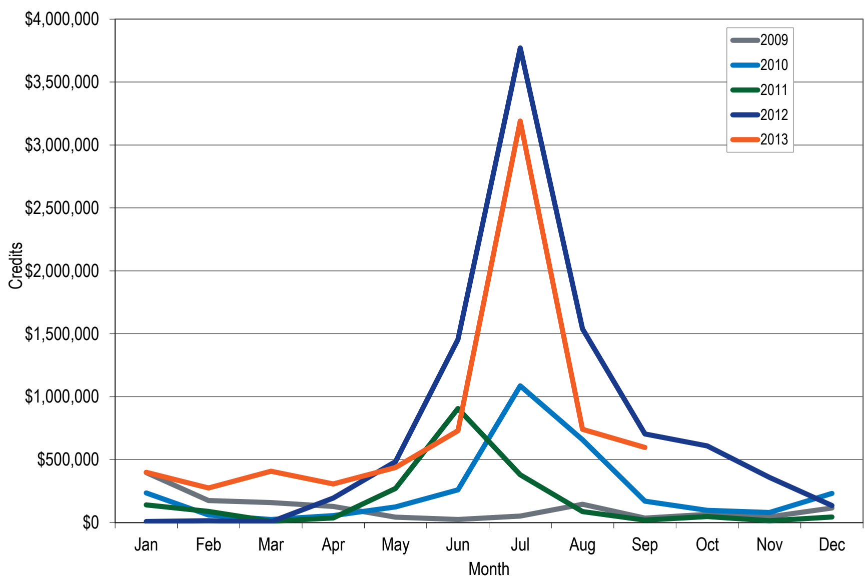


Table 6-4 shows the first nine months of 2012 and 2013 performance in the Economic Program by control zone and participation type. Curtailed energy for the Economic Program was 114,379 MWh and the total payment amount was $7,088,205. The Dominion Control Zone accounted for $4,079,022 or 58 percent of all Economic Program credits, associated with 66,847 MWh or 58 percent of total program reductions. Table 6-4 shows the average participation in the Economic Program by zone and amount of customers in each zone. The Dominion Control Zone has the highest average MW reductions per customer and average credits per customer. Credits for the first nine months of 2013 decreased by $1,084,448, or 13 percent, compared to the same time period of 2012. However, this does not fully account for data lag in September settlements by demand response providers that have up to 60 days to submit data after a demand response event. The total credits decreased by three percent from the first seven months of 2012 compared to the first seven months of 2013.

Table 6-4 PJM Economic Program participation by zone: January through September 2012 and 2013

	Credits			MWh Reductions		
	2012	2013	Percentage Change	2012	2013	Percentage Change
AECO	$20,555	$19,459	(5%)	98	143	46%
AEP	$13,272	$27,648	108%	172	939	445%
AP	$933,407	$164,594	(82%)	14,000	2,579	(76%)
ATSI	$9,034	$24,612	172%	110	8,094	7,251%
BGE	$181,086	$642,144	255%	1,005	3,416	240%
ComEd	$434,132	$612,568	41%	7,541	12,445	65%
DAY	$0	$0	NA	0	0	NA
DEOK	$0	$60,279	NA	0	986	NA
DLCO	$3,032	$0	(100%)	44	0	(100%)
Dominion	$3,503,563	$4,079,022	16%	51,442	66,847	30%
DPL	$37,698	$18,315	(51%)	280	117	(58%)
EKPC	$0	$0	NA	0	0	NA
JCPL	$244,640	$404,022	65%	2,062	2,467	20%
Met-Ed	$203,409	$9,643	(95%)	2,830	110	(96%)
PECO	$589,933	$85,781	(85%)	7,875	2,322	(71%)
PENELEC	$420,885	$273,935	(35%)	7,967	4,722	(41%)
Pepco	$118,789	$5	(100%)	1,051	0	(100%)
PPL	$448,208	$267,310	(40%)	4,845	4,884	1%
PSEG	$1,011,011	$398,867	(61%)	20,060	4,309	(79%)
RECO	$0	$0	NA	0	0	NA
Total	$8,172,654	$7,088,205	(13%)	121,381	114,379	(6%)

Table 6-5 shows total settlements submitted by month for 2008 through September 2013. July of 2012 had 1,761 more settlement days compared to July of 2013. September does not include all of the settlement days because of the 60 day lag.

Table 6-6 shows the number of distinct Curtailment Service Providers (CSPs) and distinct participants actively submitting settlements by month for the period 2009 through September 2013.[7] The number of active participants during the first nine months of 2013 decreased by 217 compared to the same period in 2012. The smaller number of active customers in 2013 responded more frequently compared to customers in the same period of 2012.

Table 6-5 Settlement days submitted by month in the Economic Program: 2008 through September 2013

Month	2008	2009	2010	2011	2012	2013
Jan	2,916	1,264	1,415	562	62	192
Feb	2,811	654	546	148	30	92
Mar	2,818	574	411	82	46	126
Apr	3,406	337	338	102	93	160
May	3,336	918	673	298	144	189
Jun	3,184	2,727	1,221	743	1,480	402
Jul	3,339	2,879	3,010	1,412	2,906	1,145
Aug	3,848	3,760	2,158	793	1,693	573
Sep	3,264	2,570	660	294	555	491
Oct	1,977	2,361	699	66	481	
Nov	1,105	2,321	672	51	280	
Dec	986	1,240	894	40	124	
Total	32,990	21,605	12,697	4,591	7,894	3,370

Table 6-6 Distinct participants and CSPs submitting settlements in the Economic Program by month: 2009 through September 2013

	2009		2010		2011		2012		2013	
Month	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
Jan	17	257	11	153	5	40	5	15	8	47
Feb	12	129	9	92	6	29	3	9	5	14
Mar	11	149	7	124	3	15	3	12	5	19
Apr	9	76	5	77	3	15	3	8	5	16
May	9	201	6	140	6	144	5	20	6	33
Jun	20	231	11	152	10	304	16	338	9	53
Jul	21	183	18	267	15	214	21	383	17	215
Aug	15	400	14	317	14	186	17	361	12	67
Sep	11	181	11	96	7	47	11	127	15	149
Oct	11	93	8	37	3	9	9	50		
Nov	9	143	7	38	3	13	5	63		
Dec	10	160	7	44	5	12	3	10		
Total Distinct Active	25	747	24	438	20	610	24	520	22	288

7 September credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could account for a maximum lag of approximately 74 calendar days.

Table 6-7 shows a frequency distribution of MWh reductions and credits in each hour for the first nine months of 2012 and 2013. In the first nine months of 2013, 50.6 percent of the reductions occurred between hour ending 15 and hour ending 18, while in the first nine months of 2012, 54.8 percent of hourly reductions occurred during those hours.

Table 6-7 Hourly frequency distribution of Economic Program MWh reductions and credits: January through September 2012 and 2013

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2012	2013	Percentage Change	2012	2013	Percentage Change
1	141	152	8%	$4,124	$5,101	24%
2	142	140	(1%)	$3,514	$3,303	(6%)
3	142	140	(2%)	$1,733	$2,520	45%
4	134	139	4%	$137	$1,683	NA
5	135	145	7%	$673	$1,687	NA
6	201	152	(24%)	$3,304	$3,592	9%
7	960	3,616	277%	$31,493	$192,380	511%
8	2,028	4,353	115%	$56,806	$266,427	369%
9	2,828	4,440	57%	$92,999	$213,000	129%
10	3,020	4,382	45%	$112,694	$194,191	72%
11	3,557	3,771	6%	$159,326	$180,371	13%
12	4,314	3,614	(16%)	$228,530	$162,849	(29%)
13	7,489	5,756	(23%)	$533,585	$304,535	(43%)
14	11,625	9,727	(16%)	$775,030	$776,812	0%
15	15,992	14,052	(12%)	$1,157,989	$908,191	(22%)
16	17,074	15,316	(10%)	$1,415,885	$1,044,855	(26%)
17	17,026	15,377	(10%)	$1,420,189	$1,045,575	(26%)
18	16,416	13,173	(20%)	$1,245,547	$879,634	(29%)
19	7,353	9,374	27%	$448,900	$541,560	21%
20	4,860	3,890	(20%)	$229,341	$212,163	(7%)
21	2,684	1,410	(47%)	$135,777	$87,057	(36%)
22	1,822	701	(62%)	$73,886	$38,162	(48%)
23	828	330	(60%)	$24,813	$13,735	(45%)
24	609	229	(62%)	$16,379	$8,820	(46%)
Total	121,381	114,379	(6%)	8,172,654	7,088,205	(13%)

Following the implementation of Order 745 on April 1, 2012, demand resources were paid full LMP for any load reductions during the hours they were dispatched, provided that LMP was greater than the Net Benefits Test (NBT) threshold. The NBT is used to define a price point above which the net benefits of DR are deemed to exceed the cost to load. When the LMP is above the NBT threshold, the demand response resource receives credit for the full LMP. The Net Benefits Test defined an average price of $27.50 from January through September 2013. Demand resources are not paid for any load reductions during hours where the LMP is below the Net Benefits Test price.

Table 6-8 shows the frequency distribution of Economic Program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP.

Total Economic Program reductions decreased by 7,002 MWh, from 121,381 MWh in the first nine months of 2012 to 114,379 MWh in the same time period of 2013. Reductions occurred at all price levels. Approximately 71.5 percent of MWh reductions and 54.4 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75. MWh reductions in the first nine months of 2013 decreased 5.8 percent compared to the same period in 2012. However, the 2013 data is not fully representative of activity in September due to the lag in settlements by demand response providers that have up to 60 days to submit data after a demand response event. The total MWh reductions decreased by seven percent from the first seven months of 2013 compared to the first seven months of 2012.

Table 6-8 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through September 2012 and 2013

	MWh Reductions			Program Credits		
LMP	2012	2013	Percentage Change	2012	2013	Percentage Change
$0 to $25	1,433	525	(64.8%)	$8,893	$13,361	50.2%
$25 to $50	62,853	58,721	(6.6%)	$2,382,790	$2,431,227	2.0%
$50 to $75	28,105	23,008	(18.1%)	$1,714,893	$1,423,356	(17.0%)
$75 to $100	10,722	8,447	(21.2%)	$936,533	$583,971	(37.6%)
$100 to $125	6,048	8,112	34.1%	$711,440	$789,421	11.0%
$125 to $150	3,925	4,980	26.9%	$534,845	$614,937	15.0%
$150 to $200	2,677	2,237	(16.4%)	$459,682	$346,071	(24.7%)
$200 to $250	2,927	3,296	12.6%	$616,602	$300,421	(51.3%)
$250 to $300	1,777	781	(56.1%)	$471,389	$203,610	(56.8%)
> $300	914	4,272	367.5%	$335,585	$381,831	13.8%
Total	121,381	114,379	(5.8%)	$8,172,654	$7,088,205	(13.3%)

Load Management Program

Table 6-9 shows zonal monthly capacity credits to DR resources for the period January through September of 2013. Capacity revenue increased in the first nine months of 2013 by $33.8 million, or 12.8 percent, compared to the first nine months of 2012, from $263.7 million to $297.4 million in part due to higher RPM price increases for the 2013/2014 Delivery Year.[8]

Table 6-9 Zonal monthly capacity credits: January through September 2013

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$411,097	$371,313	$411,097	$397,836	$411,097	$1,002,307	$1,035,717	$1,035,717	$1,002,307	$6,078,488
AEP	$425,101	$383,962	$425,101	$411,388	$425,101	$749,663	$774,652	$774,652	$749,663	$5,119,282
AP	$185,478	$167,528	$185,478	$179,495	$185,478	$477,348	$493,260	$493,260	$477,348	$2,844,672
ATSI	$19,859	$17,937	$19,859	$19,218	$19,859	$365,564	$377,750	$377,750	$365,564	$1,583,358
BGE	$5,430,108	$4,904,613	$5,430,108	$5,254,943	$5,430,108	$7,487,232	$7,736,807	$7,736,807	$7,487,232	$56,897,957
ComEd	$405,926	$366,643	$405,926	$392,831	$405,926	$782,114	$808,185	$808,185	$782,114	$5,157,850
DAY	$63,670	$57,508	$63,670	$61,616	$63,670	$42,849	$44,278	$44,278	$42,849	$484,388
DEOK	$8,185	$7,393	$8,185	$7,921	$8,185	$16,115	$16,653	$16,653	$16,115	$105,403
DLCO	$49,718	$44,907	$49,718	$48,114	$49,718	$143,269	$148,045	$148,045	$143,269	$824,803
Dominion	$306,929	$277,226	$306,929	$297,028	$306,929	$585,863	$605,391	$605,391	$585,863	$3,877,548
DPL	$1,547,049	$1,397,335	$1,547,049	$1,497,145	$1,547,049	$1,915,174	$1,979,013	$1,979,013	$1,915,174	$15,324,002
EKPC	$0	$0	$0	$0	$0	$1,495	$1,544	$1,544	$1,495	$6,078
JCPL	$1,495,628	$1,350,890	$1,495,628	$1,447,382	$1,495,628	$2,215,048	$2,288,883	$2,288,883	$2,215,048	$16,293,015
Met-Ed	$1,044,281	$943,222	$1,044,281	$1,010,595	$1,044,281	$2,174,111	$2,246,581	$2,246,581	$2,174,111	$13,928,045
PECO	$2,660,069	$2,402,643	$2,660,069	$2,574,260	$2,660,069	$5,142,792	$5,314,219	$5,314,219	$5,142,792	$33,871,131
PENELEC	$1,144,857	$1,034,064	$1,144,857	$1,107,926	$1,144,857	$2,884,571	$2,980,723	$2,980,723	$2,884,571	$17,307,149
Pepco	$1,906,591	$1,722,082	$1,906,591	$1,845,088	$1,906,591	$4,092,964	$4,229,396	$4,229,396	$4,092,964	$25,931,661
PPL	$3,247,272	$2,933,020	$3,247,272	$3,142,521	$3,247,272	$7,019,745	$7,253,736	$7,253,736	$7,019,745	$44,364,319
PSEG	$2,354,400	$2,126,555	$2,354,400	$2,278,452	$2,354,400	$8,574,172	$8,859,978	$8,859,978	$8,574,172	$46,336,509
RECO	$14,896	$13,454	$14,896	$14,415	$14,896	$249,408	$257,721	$257,721	$249,408	$1,086,813
Total	$22,721,111	$20,522,294	$22,721,111	$21,988,172	$22,721,111	$45,921,805	$47,452,531	$47,452,531	$45,921,805	$297,422,472

8 For more detail on RPM prices see the *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

Table 6-10 shows the amount of Energy Efficiency resources in each LDA for the 2012/2013 and 2013/2014 Delivery Year. The total MW of Energy Efficiency resources increased by 63 percent from 631.2 MW in 2012/2013 to 1,029.2 MW in 2013/2014 Delivery Year.

Table 6-10 LDA Energy Efficiency resources by MW: 2012/2013 and 2013/2014 Delivery Year

	EE ICAP (MW)			EE UCAP (MW)		
LDA Name	2012/2013	2013/2014	Percentage Change	2012/2013	2013/2014	Percentage Change
DPL-SOUTH	0.0	12.4	NA	0.0	12.9	NA
EMAAC	18.7	17.3	(7%)	19.0	17.1	(10%)
MAAC	44.3	81.1	83%	45.7	83.9	84%
Pepco	0.0	74.6	NA	0.0	77.5	NA
PS-NORTH	6.6	10.4	58%	6.8	10.8	59%
PSEG	6.1	13.1	115%	6.1	13.3	118%
RTO	395.5	593.5	50%	410.0	617.5	51%
SWMAAC	138.6	188.5	36%	143.6	196.2	37%
Total	609.8	990.9	62%	631.2	1,029.2	63%

Table 6-11 shows the MW registered by measurement and verification method and by load drop method. Of the DR MW committed, 3.5 percent use the Guaranteed Load Drop measurement and verification method, 86.9 percent use Firm Service Level method and 9.6 percent use Direct Load Control.

The load drop method is labeled as Other for 3.6 percent of committed MW. The MMU recommends that any MW designated as Other explicitly record the method of load drop.

Table 6-12 shows the fuel type used in the on-site generators identified in Table 6-11. Of the load management resources identified as using on-site generation, 80.6 percent of MW are diesel, 5.5 percent are natural gas and 13.8 percent is coal, oil, other or no fuel source.

Table 6-11 Reduction MW by each demand response method: 2013/2014 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other MW	Total	Percentage by type
Firm Service Level	1,766.7	1,371.9	242.1	698.1	3,311.3	91.8	258.0	7,739.9	86.9%
Guaranteed Load Drop	62.0	165.8	4.1	23.0	33.9	0.7	23.8	313.4	3.5%
Non hourly metered sites (DLC)	0.0	775.6	0.0	0.0	0.0	40.0	37.0	852.6	9.6%
Total	1,828.7	2,313.4	246.1	721.1	3,345.2	132.6	318.8	8,905.9	100.0%
Percentage by method	20.5%	26.0%	2.8%	8.1%	37.6%	1.5%	3.6%	100.0%	

Table 6-12 On-site generation fuel type by MW: 2013/2014 Delivery Year

Fuel Type	MW	Percentage
Coal	1.0	0.1%
Diesel	1,474.4	80.6%
Natural Gas	101.2	5.5%
None	236.8	12.9%
Oil	8.7	0.5%
Other	6.6	0.4%
Total	1,828.7	100.00%

Load Management Event Reported Compliance

In the first nine months of 2013, PJM declared five Load Management events, on July 15, July 16, July 18, September 10 and September 11. There were two events during the 2012/2013 Delivery Year and one event in the 2011/2012 Delivery Year. These events affected resources committed for the 2013/2014 Delivery Year. Since each of these events occurred within the summer compliance period, each was considered in compliance assessment. Table 6-13 has the Demand Response cleared UCAP MW per zone by Delivery Year. Total Demand Response cleared in PJM increased from 1.4 percent in the 2011/2012 Delivery Year to 6.7 percent in the 2013/2014 Delivery Year.

Table 6-13 Demand Response Cleared MW UCAP by Zone: 2011/2012 through 2013/2014 Delivery Year

	2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year	
Zone	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP
AECO	28.9	1.6%	128.0	6.6%	184.5	9.3%
AEP	120.5	1.7%	926.6	13.1%	996.6	11.8%
AP	130.4	1.3%	541.7	5.1%	667.6	6.6%
ATSI	31.1	90.7%	128.5	23.1%	565.0	4.6%
BGE	671.5	12.7%	1,326.7	20.9%	1,126.9	17.4%
ComEd	127.8	0.5%	970.5	4.0%	985.1	3.7%
DAY	17.5	0.7%	127.1	5.0%	59.6	2.7%
DEOK	NA	NA	62.1	5.4%	88.2	7.6%
DLCO	15.6	0.5%	110.2	4.1%	194.5	6.9%
Dominion	112.3	0.5%	680.6	2.9%	744.1	3.2%
DPL	56.5	1.3%	323.5	7.1%	302.4	6.5%
EKPC	NA	NA	NA	NA	12.3	3.0%
JCPL	60.8	1.6%	346.2	8.3%	308.6	7.2%
Met-Ed	27.9	0.7%	277.2	6.7%	340.1	7.6%
PECO	115.0	1.2%	652.5	6.0%	720.7	6.5%
PENELEC	23.5	0.3%	307.9	4.0%	471.0	6.0%
PEPCO	161.6	2.8%	467.7	8.7%	661.9	11.4%
PPL	81.2	0.8%	842.3	7.4%	1,131.0	9.6%
PSEG	44.2	0.4%	517.8	4.6%	1,185.0	9.9%
RECO	0.3	100.0%	3.8	100.0%	34.5	100.0%
Total	1,826.6	1.4%	8,740.9	6.2%	10,779.6	6.7%

Table 6-14 lists Load Management Events declared by PJM in the first nine months of 2013 and the affected zones. ATSI was the only zone called for all five events.

PJM deployed both long lead time resources, which require more than one hour but less than two hours notification, and short lead time resources, which require less than an hour notification. Any resource is eligible to be either a short lead time or long lead time resource, and there are no differences in payment for these resources. The nominal ICAP stated in event compliance tables here will not equal total nominal ICAP for the zone, as not all resources were called in each zone during the events. Approximately 99.5 percent of registrations, accounting for 91.8 percent of registered MW, are designated as long lead time resources.

Table 6-14 PJM declared Load Management Events: 2013

Event Date	Event Times	Compliance Hours	Minutes not counted	Lead Time	Geographical Area
15-Jul-13	15:50-18:22	16:00-18:00	32	Long Lead	ATSI
16-Jul-13	13:30-16:30	14:00-16:00	60	Long Lead	ATSI
18-Jul-13	14:40-18:00	15:00-18:00	20	Long Lead	ATSI
	14:40-17:00	15:00-17:00	20	Long Lead	PECO, PPL
	15:00-18:00	15:00-18:00	0	Long Lead	AEP Canton Subzone
10-Sep-13	15:50-21:30	16:00-20:00	100	Long Lead	ATSI
	16:45-21:30	17:00-20:00	115	Long Lead	AEP Canton Subzone
11-Sep-13	13:30-19:30	14:00-19:00	60	Long Lead	AEP
	14:00-20:00	14:00-20:00	0	Long Lead	ATSI
	14:00-17:15	14:00-17:00	15	Short Lead	AECO, BGE, DPL, JCPL, Met-Ed, PECO, Penelec, Pepco, PPL, PSEG, RECO
	14:30-18:30	15:00-18:00	60	Long Lead	Dominion
	15:00-17:00	15:00-17:00	0	Long Lead	AECO, JCPL, PSEG, RECO
	15:00-17:30	15:00-17:30	30	Long Lead	Met-Ed, PECO, PPL
	15:00-18:00	15:00-18:00	0	Long Lead	BGE, DPL, Pepco
	15:00-18:30	15:00-18:00	30	Long Lead	Penelec, DLCO

There were two events in 2013 for which PJM requested voluntary subzonal dispatch of emergency demand side resources. While PJM may voluntarily declare Load Management Events for part of a zone, the only locational requirement for the aggregation of multiple end use customers to a single registration is that they reside in the same control zone. Similarly, compliance for testing and for zonal Emergency Events is aggregated for each CSP to a zonal level.

Subzonal dispatch by zipcode is currently voluntary but will be mandatory beginning with the 2014/2015 delivery year. More locational deployment of Load Management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Table 6-15 shows the performance for the July 15, 2013 event. The first column shows the nominated value, which is the reduction capability indicated by the participant at registration. The second column shows Load Management MW commitments, which are used to assess RPM compliance. Differences between these two columns reflect, in part, differences between MW offered and cleared for any partially cleared DR resource. In addition, RPM commitments consider any RPM transactions, such as capacity replacement sales or purchases for Demand Resources, while the nominal ICAP does not, although resources fully buying out of their commitments are not included in this analysis. The third column shows the observed load reduction in MWh, or the reported load drop during the hours of an event.

Overall, the reported performance was 97.5 percent, or 672.7 MW out of 690.0 MW committed. This reported performance value treated locations showing negative performance or non-reporting as zero performance.

Table 6-15 Load Management event performance: July 15, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
ATSI	810.7	690.0	672.7	(17.3)	97.5%	83.0%
Total	810.7	690.0	672.7	(17.3)	97.5%	83.0%

Table 6-16 shows the performance for the July 16, 2013, event. ATSI was the only zone called for this event. The reported performance was 91.4 percent, or 630.7 MW out of 690.0 MW committed. This reported performance value treated locations showing negative performance or non-reporting as zero performance.

Table 6-16 Load Management event performance: July 16, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
ATSI	802.2	690.0	630.7	(59.3)	91.4%	78.6%
Total	802.2	690.0	630.7	(59.3)	91.4%	78.6%

Table 6-17 shows the performance for the July 18, 2012 event. Overall, the performance was 92.8 percent, or 1,645.0 MW out of 1,772.2 MW committed. The ATSI and PECO Zones had 87.4 and 82.6 percent compliance. This was the third event for ATSI during this week, and the compliance results decreased from an observed 672.7 MWh reduction on July 15, 2013, to an observed 630.7 MWh reduction on July 16 and an observed 603.1 MWh reduction on July 18, 2013. The AEP Canton Subzone dispatch was not mandatory, but the subzone performed at 100.6 percent compliance with 93.8 MW out of 93.2 MW committed. This reported performance value treated locations showing negative performance as zero performance.

Table 6-17 Load Management event performance: July 18, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
ATSI	797.7	690.0	603.1	(86.9)	87.4%	75.6%
PECO	733.2	410.1	338.6	(71.6)	82.6%	46.2%
PPL	791.8	578.8	609.6	30.7	105.3%	77.0%
AEP Canton Subzone	129.4	93.2	93.8	0.6	100.6%	72.5%
Total	2,452.1	1,772.2	1,645.0	(127.2)	92.8%	67.1%

Table 6-18 Load Management event performance: September 10, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
ATSI	808.8	690.0	597.0	(93.0)	86.5%	73.8%
AEP Canton Subzone	129.4	93.2	55.1	(38.1)	59.1%	42.6%
Total	938.2	783.2	652.1	(131.1)	83.3%	69.5%

Table 6-18 shows the performance for the September 10, 2013 event. The event continued past the mandatory compliance period and the hourly data past the compliance period does not count towards the compliance value for PJM. This was the fourth event in the ATSI zone and the zone delivered 86.5 percent of its committed MW, or 597.0 MW. The AEP Canton Subzone delivered 59.1 percent of its committed MW, or 55.1 MW. This was the second call for the subzone, and it was not mandatory based on the current PJM rules for the 2013/2014 Delivery Year.

Table 6-19 shows the performance for the September 11, 2013 event. The Short Lead call covered three zones, Met-Ed, Penelec, and RECO, that did not have any Short Lead resources. This was the fifth call in the ATSI Zone, and its performance decreased to the lowest for all the events at 84.5 percent compliance, or 582.9 MW. The Short Lead resources in the PPL Zone only had 0.3 MW nominated out of the 42.6 MW committed. The 0.3 MW performed during the event, but the compliance for PPL's short lead resources was only 0.7 percent. AEP and DPL's Short Lead resources over performed at 158.1 percent and 158.8 percent compliance.

Table 6-19 Load Management event performance: September 11, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	126.3	102.5	95.7	(6.8)	93.3%	75.7%
AECO Long Lead	84.5	50.7	53.8	3.2	106.2%	63.7%
AECO Short Lead	41.8	51.8	41.8	(10.0)	80.7%	100.0%
AEP	1,660.0	830.2	1,312.1	481.9	158.1%	79.0%
ATSI	826.0	690.0	582.9	(107.1)	84.5%	70.6%
BGE	860.0	627.2	697.3	70.1	111.2%	81.1%
BGE Long Lead	787.6	565.6	625.0	59.3	110.5%	79.3%
BGE Short Lead	72.4	61.6	72.4	10.8	117.5%	100.0%
DLCO	113.2	69.2	48.9	(20.3)	70.7%	43.2%
Dominion	877.3	751.7	672.9	(78.8)	89.5%	76.7%
DPL	302.2	220.3	231.4	11.1	105.0%	76.6%
DPL Long Lead	230.2	154.4	126.7	(27.7)	82.1%	55.0%
DPL Short Lead	72.0	65.9	104.7	38.8	158.8%	145.5%
JCPL	210.2	156.7	140.6	(16.1)	89.7%	66.9%
JCPL Lead Lead	190.3	136.8	113.4	(23.5)	82.9%	59.6%
JCPL Short Lead	19.9	19.9	27.2	7.3	136.9%	136.7%
Met-Ed	238.0	173.6	182.8	9.2	105.3%	76.8%
Met-Ed Long Lead	238.0	173.6	182.8	9.2	105.3%	76.8%
Met-Ed Short Lead	0.0	0.0	0.0	NA	NA	NA
PECO	591.4	410.3	301.4	(109.0)	73.4%	51.0%
PECO Long Lead	591.2	410.1	301.3	(108.9)	73.5%	51.0%
PECO Short Lead	0.2	0.2	0.1	(0.1)	64.5%	61.9%
Penelec	342.0	265.0	239.3	(25.8)	90.3%	70.0%
Penelec Long Lead	342.0	265.0	239.3	(25.8)	90.3%	70.0%
Penelec Short Lead	0.0	0.0	0.0	NA	NA	NA
Pepco	495.2	371.9	252.2	(119.7)	67.8%	50.9%
Pepco Long Lead	305.1	200.3	189.2	(11.1)	94.5%	62.0%
Pepco Short Lead	190.2	171.7	63.1	(108.6)	36.7%	33.2%
PPL	762.2	621.5	557.7	(63.8)	89.7%	73.2%
PPL Long Lead	761.9	578.8	557.4	(21.5)	96.3%	73.2%
PPL Short Lead	0.3	42.6	0.3	(42.3)	0.7%	100.0%
PSEG	475.2	350.6	277.0	(73.6)	79.0%	58.3%
PSEG Long Lead	470.1	346.1	271.8	(74.3)	78.5%	57.8%
PSEG Short Lead	5.0	4.4	5.1	0.7	116.5%	102.2%
RECO	6.4	4.0	4.8	0.7	118.0%	73.9%
RECO Long Lead	6.4	4.0	4.8	0.7	118.0%	73.9%
RECO Short Lead	0.0	0.0	0.0	NA	NA	NA
Total	**7,885.5**	**5,644.7**	**5,596.8**	**(47.9)**	**99.2%**	**71.0%**

Table 6-20 shows load management event performance for the five event days. RTO wide percent reported compliance was 100.5 percent in 2013 for resources called during emergency events. This reported performance value treated locations showing negative performance as zero performance. AEP's over performance by 481.9 MW offset under compliance in other zones. The compliance for all zones, excluding AEP, was 90.5 percent of the committed MW. The ATSI Zone had five calls and ended with an average of 88.7 percent compliance. The Pepco Zone only had one call and had 67.8 percent compliance. Every zone underperformed compared to their Nominal ICAP MW. CSPs have to register more MW than are committed in each zone to be able to deliver at the committed MW level.

Table 6-20 Load Management event performance: 2013 Aggregate

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	126.3	102.5	95.7	(6.8)	93.3%	75.7%
AEP	1,660.0	830.2	1,312.1	481.9	158.1%	79.0%
ATSI	809.1	690.0	611.7	(78.2)	88.7%	75.6%
BGE	860.0	627.2	697.3	70.1	111.2%	81.1%
DLCO	113.2	69.2	48.9	(20.3)	70.7%	43.2%
Dominion	877.3	751.7	672.9	(78.8)	89.5%	76.7%
DPL	302.2	220.3	231.4	11.1	105.0%	76.6%
JCPL	210.2	156.7	140.6	(16.1)	89.7%	66.9%
Met-Ed	238.0	173.6	182.8	9.2	105.3%	76.8%
PECO	662.3	410.3	320.0	(90.4)	78.0%	48.3%
Penelec	342.0	265.0	239.3	(25.8)	90.3%	70.0%
Pepco	495.2	371.9	252.2	(119.7)	67.8%	50.9%
PPL	777.0	621.5	583.6	(37.8)	93.9%	75.1%
PSEG	475.2	350.6	277.0	(73.6)	79.0%	58.3%
RECO	6.4	4.0	4.8	0.7	118.0%	73.9%
Total	7,954.3	5,644.7	5,670.2	25.6	100.5%	71.3%

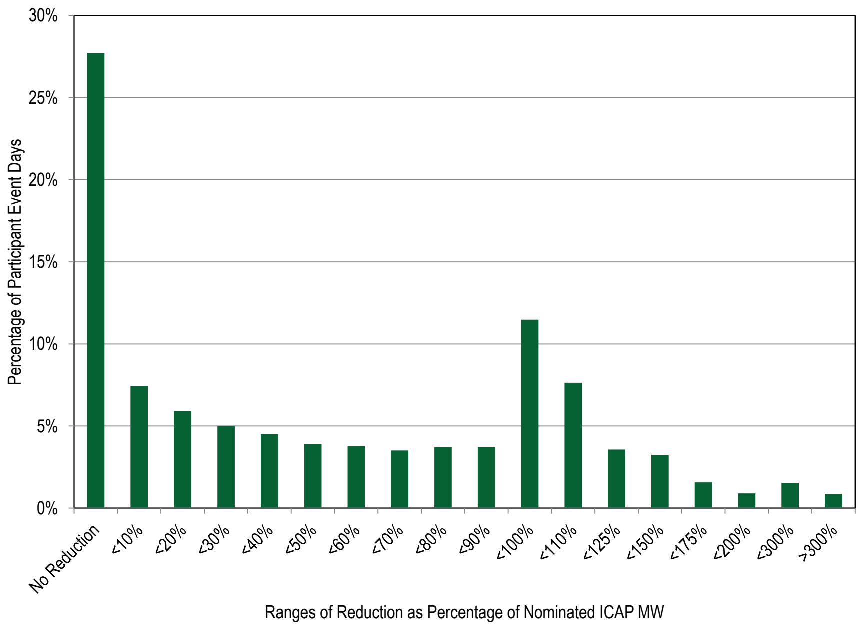
Performance for specific customers varied significantly. Table 6-21 shows the distribution of participant event days across various levels of performance for July 15, July 16, July 18, September 10 and September 11, 2013, events in the 2013/2014 compliance period. Table 6-21 includes the participation for Subzonal and Zonal dispatch. For these events, approximately 28 percent of participants showed no reduction, load increased or participants did not report data. Approximately 54 percent of participants provided less than half of their committed MW. The majority of participants, approximately 81 percent, provided less than 100 percent reduction compared to their commitment. Figure 6-3 shows the data in Table 6-21.[9] The distribution includes high frequencies of both under performing and over performing registrations.

Table 6-21 Distribution of participant event days across ranges of performance levels across the event in the 2013/2014 Delivery Year compliance period

Ranges of performance as a percentage of nominated ICAP MW	Number of participant event days	Proportion of participant event days	Cumulative proportion
0%, load increase, or no reporting	5,013	28%	28%
0% - 10%	1,345	7%	35%
10% - 20%	1,069	6%	41%
20% - 30%	906	5%	46%
30% - 40%	814	5%	51%
40% - 50%	705	4%	54%
50% - 60%	681	4%	58%
60% - 70%	635	4%	62%
70% - 80%	671	4%	65%
80% - 90%	674	4%	69%
90% - 100%	2,076	11%	81%
100% - 110%	1,381	8%	88%
110% - 125%	645	4%	92%
125% - 150%	588	3%	95%
150% - 175%	283	2%	97%
175% - 200%	163	1%	98%
200% - 300%	278	2%	99%
> 300%	158	1%	100%
Total	18,085	100%	

9 Participant event days, shown in Figure 6-3, and Table 6-20, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant event day. The load reduction values associated do not reflect actual MWh curtailments, but average curtailments in each event, summed for all events in the period.

Figure 6-3 Distribution of participant event days across ranges of performance levels across the event in the 2013/2014 Delivery Year compliance period



Load Management Analysis

Currently, load management event rules allow over-compliance to be reported when there is no actual over-compliance. Settlement locations with a negative load reduction value (load increase) are netted within registrations, within hours. For example, if a registration had two locations, one with a 50 MWh load increase, and another with a 75 MWh load reduction, compliance for that registration would show a 75 MWh load reduction for that event hour. Settlement MWh are not netted across hours or across registrations for compliance purposes, but are set to zero if they are negative. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would show a 30 MWh reduction in hour two and an average hourly 15 MWh load reduction for that two hour event. Reported compliance is less than actual compliance, as locations with a negative reduction are treated as zero for compliance purposes. Overall, 20 percent of event hours reported showed negative reductions, or an increase in the load at the site.

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 4.6 percent of locations were not submitted to PJM for compliance purposes. While the performance of these resources is not known, it is reasonable to assume, given the incentives to report reductions, that these locations had negative compliance (load increases relative to baseline), further skewing reported compliance values and performance penalties. Registrations with negative compliance are treated as zero for the purposes of imposing penalties and reporting.

Table 6-22 shows load management event performance, explicitly netting out negative load reduction values that were reported. These reported negative values were set to zero in PJM's reported compliance values, consistent with the rules. The Actual compliance numbers conservatively assume that non-reporting locations were zero. Compliance decreases from 100.5 percent to 90.7 percent when known negative compliance is included. Considering all and only reported values, the observed load reduction of the five events in 2013 was 5,028.0 MW, rather than the 5,670.2 MW reported. It is likely that these results still overstate compliance, as 10.3 percent of locations did not report for 2013 event compliance and these locations are assumed to have a zero reduction. Accounting for negative compliance and requiring all CSPs to submit all data for each location will result in more accurate measures of Demand Response performance.

Table 6-22 Load Management Event Performance with negative compliance: 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	126.3	102.5	88.9	(13.6)	86.7%	70.4%
AEP	1,660.0	830.2	1,201.4	371.3	144.7%	72.4%
ATSI	809.5	690.0	474.8	(215.2)	68.8%	58.7%
BGE	860.0	627.2	676.7	49.5	107.9%	78.7%
DLCO	113.2	69.2	38.6	(30.6)	55.7%	34.1%
Dominion	877.3	751.7	612.4	(139.3)	81.5%	69.8%
DPL	302.2	220.3	217.1	(3.3)	98.5%	71.8%
JCPL	210.2	156.7	117.9	(38.8)	75.2%	56.1%
Met-Ed	238.0	173.6	170.1	(3.5)	98.0%	71.5%
PECO	662.3	410.3	249.0	(161.3)	60.7%	37.6%
Penelec	342.0	265.0	239.3	(25.8)	90.3%	70.0%
Pepco	495.2	371.9	241.1	(130.9)	64.8%	48.7%
PPL	777.0	621.5	546.7	(74.7)	88.0%	70.4%
PSEG	475.2	350.6	239.3	(111.3)	68.3%	50.4%
RECO	6.4	4.0	3.8	(0.3)	93.6%	58.6%
Total	7,828.4	5,542.2	5,028.0	(514.2)	90.7%	64.2%

Table 6-23 shows the difference between actual performance and reported performance, including the negative values that were measured during emergency events. This adjustment shows less than 100 percent compliance all zones but AEP and BGE. Actual compliance for the ATSI zone was 68.8 percent rather than 88.7 percent.

Table 6-23 Load Management Event Performance Comparison: Reported Reduction vs. Actual Reduction: 2013

Zone	Committed MW	Load Reduction Reported (MWh)	Actual Load Reduction (MWh)	Difference	Percent Compliance Reported	Percent Compliance Actual
AECO	102.5	95.7	88.9	6.8	93.3%	86.7%
AEP	830.2	1,312.1	1,201.4	110.7	158.1%	144.7%
ATSI	690.0	611.7	474.8	137.0	88.7%	68.8%
BGE	627.2	697.3	676.7	20.6	111.2%	107.9%
DLCO	69.2	48.9	38.6	10.3	70.7%	55.7%
Dominion	751.7	672.9	612.4	60.5	89.5%	81.5%
DPL	220.3	231.4	217.1	14.4	105.0%	98.5%
JCPL	156.7	140.6	117.9	22.7	89.7%	75.2%
Met-Ed	173.6	182.8	170.1	12.7	105.3%	98.0%
PECO	410.3	320.0	249.0	71.0	78.0%	60.7%
Penelec	265.0	239.3	239.3	0.0	90.3%	90.3%
Pepco	371.9	252.2	241.1	11.2	67.8%	64.8%
PPL	621.5	583.6	546.7	36.9	93.9%	88.0%
PSEG	350.6	277.0	239.3	37.7	79.0%	68.3%
RECO	4.0	4.8	3.8	1.0	118.0%	93.6%
Total	5,644.7	5,670.2	5,116.9	553.3	100.5%	90.6%

Table 6-24 shows the number of locations attached to registrations that did not report during 203 event days. In total, 10.3 percent of locations did not report during event days in 2013 and were assigned zero load response MW in the actual PJM accounting for those events. It is likely that these locations were not responding to the emergency event and had loads greater than their committed MW for those locations, and the corresponding registrations.

Table 6-24 Non Reporting Locations on 2013 Event Days

Event Date	Zone	Locations Not Reporting	Total Locations	Percent Non Reporting
15-Jul-13	ATSI	59	820	7.2%
16-Jul-13	ATSI	55	822	6.7%
18-Jul-13	ATSI	55	810	6.8%
	PECO	52	1,526	3.4%
	PPL	10	1,488	0.7%
	AEP Canton Subzone	24	76	31.6%
10-Sep-13	ATSI	129	816	15.8%
	AEP Canton Subzone	19	76	25.0%
11-Sep-13	AECO	35	278	12.6%
	AEP	76	1,432	5.3%
	ATSI	115	820	14.0%
	BGE	150	1,026	14.6%
	DLCO	40	285	14.0%
	Dominion	123	926	13.3%
	DPL	123	612	20.1%
	JCPL	121	494	24.5%
	Met-Ed	26	486	5.3%
	PECO	217	1,511	14.4%
	Penelec	14	626	2.2%
	Pepco	185	724	25.6%
	PPL	67	1,485	4.5%
	PSEG	196	1,173	16.7%
	RECO	0	19	0.0%
Total		1,891	18,331	10.3%

Table 6-25 shows the nominated capacity of non-reporting locations. Approximately 4.7 percent of nominated capacity, by MW, during event days did not report. It is likely that these locations had load above or equal to their commitment and took no action to reduce load during the PJM declared emergency.

Along with the removal of load increases from compliance, non-reporting can cause an overstatement of load reductions of the reported load at a node. The MMU recommends that compliance rules be revised to require submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations. Negative event performance of a portfolio should be netted against the positive performance of other resources. Reported compliance should include those locations that increased load in addition to those that reduced load during an emergency event.

Table 6-25 Non Reporting Locations by MW on 2013 Event Days

Event Date	Zone	Nominated ICAP Not Reporting	Nominated ICAP	Percent Non Reporting
15-Jul-13	ATSI	13.0	810.7	1.6%
16-Jul-13	ATSI	11.7	802.2	1.5%
18-Jul-13	ATSI	11.1	797.7	1.4%
	PECO	11.3	733.2	1.5%
	PPL	1.8	791.8	0.2%
	AEP Canton Subzone	14.5	129.4	11.2%
10-Sep-13	ATSI	43.1	808.8	5.3%
	AEP Canton Subzone	13.9	129.4	10.8%
11-Sep-13	AECO	8.3	126.3	6.6%
	AEP	12.8	1,660.0	0.8%
	ATSI	32.0	826.0	3.9%
	BGE	59.5	860.0	6.9%
	DLCO	8.7	113.2	7.7%
	Dominion	33.9	877.3	3.9%
	DPL	39.2	302.2	13.0%
	JCPL	31.4	210.2	15.0%
	Met-Ed	4.6	238.0	1.9%
	PECO	69.2	591.4	11.7%
	Penelec	3.0	342.0	0.9%
	Pepco	59.0	495.2	11.9%
	PPL	67.4	762.2	8.8%
	PSEG	60.8	475.2	12.8%
	RECO	0.0	6.4	0.0%
Total		610.3	12,888.8	4.7%

Emergency Energy Payments

For any PJM declared Load Management event in 2013, participants registered under the Full Option of the Emergency Load Response Program that were deployed and that demonstrated a load reduction were eligible to receive emergency energy payments, which are equal to the higher of hourly zonal LMP or an energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. The new scarcity pricing rules increased the maximum DR energy price offer for the 2013/2014 Delivery Year to $1,800/MWh. The maximum offer increases to $2,100/MWh for the 2014/2015 and $2,700/MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000/MWh.[10]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 6-26 shows the distribution of registrations and associated MW in the Emergency Full Option across ranges of minimum dispatch prices. The majority of participants, 69.7 percent, have a minimum dispatch price of $1,000/MWh, and 18.4 percent of participants have a dispatch price of $1,800/MWh, which is the maximum allowed for the 2013/2014 Delivery Year. Energy offers are further increased by submitted shutdown costs, which, in the 2013/2014 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective energy offer. The shutdown cost of resources with $500 - $999 strike prices had the highest average at $1,881.32 per registration.

Until this year, shutdown costs have not been adequately defined in Manual 15. PJM's Cost Development Subcommittee recently approved changes in Manual 15 to eliminate shutdown costs for Demand Response Resources. Going forward, and according to the changes in Manual 15, "Demand Side Response shutdown costs shall be zero."[11]

Table 6-26 Distribution of registrations and associated MW in the Emergency Full Option across ranges of Minimum Dispatch Prices effective for the 2013/2014 Delivery Year[12]

Ranges of Strike Prices ($/MWh)	Registrations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Registration
$0-$1	538	3.6%	971.2	9.2%	$0.00
$1-$200	905	6.0%	536.1	5.1%	$8.73
$200-$500	216	1.4%	190.8	1.8%	$141.90
$500-$999	133	0.9%	138.9	1.3%	$1,881.32
$1,000	10,499	69.7%	6,891.9	65.2%	$0.04
$1,000-$1,799	0	0.0%	0.0	0.0%	$0.00
$1,800	2,776	18.4%	1,833.7	17.4%	$0.00
Total	15,067	100%	10,562.6	100%	$37.32

Table 6-27 shows emergency credits and make whole payments for each event in 2013 by zone. The emergency credit is the market value of the load reductions observed during the event, based on applicable zonal LMPs. Make whole payments are the difference between the market value of the load reduction and the submitted energy offer, which includes the strike price and shutdown cost of each resource. The LMP in ATSI was $1,705.04/MWh on average during the July 18, 2013 event, resulting in a total make whole payment in the ATSI zone of $181,551.93, compared to an average of $96.48/MWh during the July 16, 2013 event, which resulted in $1,669,845.10 in make whole payments, a difference of $1,488,293.17.[13]

Table 6-27 Emergency credits and make whole payments by event by zone: 2013

Event	Zone	Emergency Credits	Emergency Make Whole Payments	Total
15-Jul-13	ATSI	$307,182.68	$1,292,511.93	$1,599,694.61
16-Jul-13	ATSI	$157,662.19	$1,669,845.10	$1,827,507.29
18-Jul-13	AEP	$73,745.90	$623,180.50	$696,926.40
	ATSI	$552,809.78	$181,551.93	$734,361.71
	PECO	$157,718.40	$1,216,408.67	$1,374,127.07
	PPL	$246,492.69	$1,938,974.34	$2,185,467.03
Total		$1,495,611.64	$6,922,472.47	$8,418,084.11

10 139 FERC ¶ 61,057 (2012).
11 PJM: "Manual 15: Cost Development Guidelines," Revision 23 (August 1, 2013), p 51.
12 In this analysis Nominated MW does not include capacity only resources, which do not receive energy market revenue.
13 September Event data for Emergency Credits will not be available at publication date.

Energy payments in the Emergency Program differ significantly from energy payments in the Economic Program and from capacity payments through the Load Management Program in that they are not based on or tied to any market price signal. Once an event is called in a zone, these payments are guaranteed.

Limited Demand Resource Penalty Charge

Limited Demand Response Resources are required to be available for only 10 times during the months of June through September in a Delivery Year on weekdays other than PJM holidays from 12:00pm to 8:00pm EPT and be capable of maintaining an interruption for six hours. Limited demand response resources have one or two hours to reduce load once PJM initiates an event. When a provider under complies based on their committed MW, the penalty is based on the amount of under compliance, the number of events called during the DY and the cost per MW day for that provider. DR penalties are only assessed for PJM initiated events, after a compliance review is complete.

Subzonal dispatch was voluntary, so the AEP Canton Subzone dispatch was not penalized for underperformance. The penalties are assessed daily and have increased by $547,122.42 from $681,094.28 in June through September of the 2012/2013 Delivery Year compared to $1,228,216.70 of the same period in the 2013/2014 Delivery Year. Table 6-28 shows penalty charges by zone for June through September of the 2012/2013 and 2013/2014 Delivery Year. PECO had the highest penalty amount, due to the clearing prices in EMAAC and performance at 82.6 percent of the committed MW.[14] The penalties for the September 10 and September 11 events have not been assessed yet due to data lag.

Table 6-28 Penalty Charges per Zone: June through September 2012/2013 and 2013/2014 Delivery Years

	2012/2013 Penalty Charge	2013/2014 Penalty Charge
AECO	$30.50	$0.00
AEP	$47,964.30	$0.00
AP	$0.00	$0.00
ATSI	$0.00	$132,023.52
BGE	$44,738.62	$0.00
ComEd	$0.00	$0.00
DAY	$0.00	$0.00
DEOK	$0.00	$0.00
Dominion	$19,727.40	$0.00
DPL	$247,595.34	$0.00
DLCO	$0.00	$0.00
EKPC	$0.00	$0.00
JCPL	$1,782.42	$0.00
Met-Ed	$0.00	$0.00
PECO	$133,499.72	$769,238.67
PENELEC	$14,729.06	$0.00
Pepco	$167,425.48	$0.00
PPL	$198.86	$326,954.51
PSEG	$3,402.58	$0.00
RECO	$0.00	$0.00
Total	$681,094.28	$1,228,216.70

14 Refer to Section 5: Capacity, Table 5-11 for complete listing of capacity prices.

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), integrated gasification combined cycle (IGCC), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- In the first nine months of 2013, average energy market net revenues for a new entrant CT were three percent greater than in the first nine months of 2012.
- In the first nine months of 2013, average energy market net revenues for a new entrant CC were 15 percent less than in 2012.
- In the first nine months of 2013, average energy market net revenues for a new entrant coal plant were 133 percent greater than in the first nine months of 2012. This increase in net revenues was a result of the change in the relative prices of coal and gas and higher energy market prices.
- In the first nine months of 2013, average energy market net revenues for a new entrant wind plant were 15 percent greater than in the first nine months of 2012.
- In the first nine months of 2013, average energy market net revenues for a new entrant solar plant were 40 percent greater than in the first nine months of 2012.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units.

Net Revenue

When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

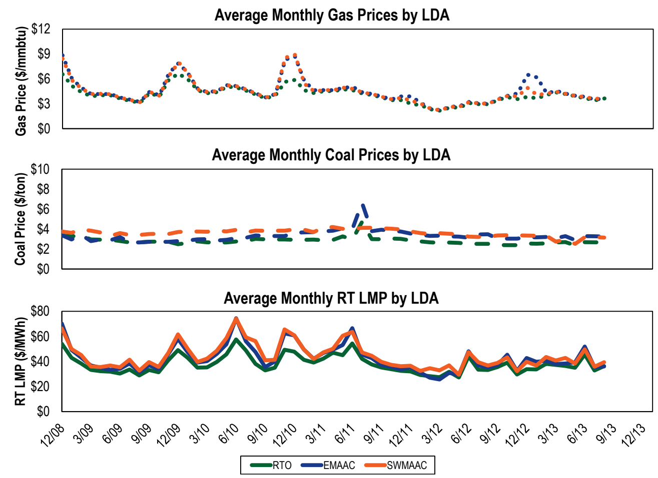
In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Operating reserve payments are included when the analysis is based on the peak-hour, economic dispatch model and actual net revenues.[1]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 13.5 percent higher in the first nine months of 2013 than in the first nine months of 2012, \$39.75 per MWh versus \$35.02 per MWh. Comparing fuel prices in the first nine months of 2013 to the first nine months of 2012, the price of Northern Appalachian coal was 0.4 percent lower; the price of Central Appalachian coal was 2.8 percent higher; the price of Powder River Basin coal was 24.1 percent higher; the price of eastern natural gas was 54.0 percent higher; and the price of western natural gas was 43.0 percent higher.

1 The peak-hour, economic dispatch model is a realistic representation of market outcomes that considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

Figure 7-1 Energy Market net revenue factor trends: December 2008 through September 2013



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on this economic dispatch scenario.

Analysis of Energy Market net revenues for a new entrant includes eight power plant configurations:

- The CT plant consists of two GE Frame 7FA.05 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction.

- The CC plant consists of two GE Frame 7FA.05 CTs equipped with evaporative cooling, duct burners' a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[2]
- The CP is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NO_x control, a Flue Gas Desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The IGCC plant consists of a coal gasification plant producing a low BTU gas product which is fired in two modified GE Frame 7FA CTs in CC configuration.
- The DS plant consists of one gas fired CAT 2 MW unit.
- The nuclear plant consists of two nuclear power units and related facilities using the Westinghouse AP1000 technology.
- The wind installation consists of twenty GE 2.5 MW wind turbines totaling 50 MW installed capacity.
- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC capacity.

Net revenue calculations for the CT, CC, CP and IGCC include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[3,4] Plant heat rates were calculated to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[5]

A forced outage rate for each class of plant was calculated from PJM data.[6] This class-specific outage rate was then incorporated into all revenue calculations. Each CT, CC, CP and IGCC plant was also given a continuous 14 day planned annual outage in the fall season. Ancillary service revenues for the provision of synchronized reserve service for all four plant types are set to zero. Ancillary service revenues for the provision of regulation service for the CT, CC and IGCC plant are also set to zero since these plant types typically do not provide regulation service in PJM. No black start service capability is assumed for any of the unit types.

Ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour.

CT generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CT generators with 20 or fewer operating years. CC generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CP generators with 30 or fewer operating years. IGCC generators are assumed to receive reactive revenues equal to the CP plant.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[7] The delivered fuel cost for natural gas reflects the estimated zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a

2 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.
3 Hourly ambient conditions supplied by Schneider Electric.
4 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour. Therefore, there is a single offer point and no offer curve.
5 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
6 Outage figures obtained from the PJM eGADS database. The CC outage rate was used for the IGCC plant.
7 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.

basis adjustment for transportation costs.[8] Coal delivered cost incorporates the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[9]

The net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM. For this economic dispatch, it was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs. If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day ahead or real time block.

Table 7-1 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[10]

Zone	2012 (Jan-Sep)	2013 (Jan-Sep)	Change in 2013 from 2012
AECO	$21,534	$22,348	4%
AEP	$14,164	$14,513	2%
AP	$18,653	$18,279	(2%)
ATSI	$15,834	$16,991	7%
BGE	$32,465	$29,660	(9%)
ComEd	$12,414	$12,785	3%
DAY	$16,115	$14,566	(10%)
DEOK	$13,862	$13,785	(1%)
DLCO	$16,857	$15,569	(8%)
Dominion	$22,496	$22,118	(2%)
DPL	$28,637	$25,623	(11%)
JCPL	$20,590	$27,155	32%
Met-Ed	$21,486	$22,297	4%
PECO	$22,364	$21,600	(3%)
PENELEC	$19,609	$21,481	10%
Pepco	$28,721	$27,931	(3%)
PPL	$19,256	$21,830	13%
PSEG	$20,251	$21,842	8%
RECO	$18,759	$24,143	29%
PJM	$20,214	$20,764	3%

8 Gas daily cash prices obtained from Platts.
9 Coal prompt prices obtained from Platts.

10 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM. For this economic dispatch scenario, it was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs.[11] If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day ahead or real time block.

Table 7-2 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year)

Zone	2012 (Jan-Sep)	2013 (Jan-Sep)	Change in 2013 from 2012
AECO	$79,559	$70,137	(12%)
AEP	$72,307	$55,813	(23%)
AP	$81,798	$64,944	(21%)
ATSI	$75,818	$63,573	(16%)
BGE	$100,381	$84,093	(16%)
ComEd	$54,600	$39,121	(28%)
DAY	$76,344	$58,018	(24%)
DEOK	$67,547	$54,732	(19%)
DLCO	$74,267	$52,607	(29%)
Dominion	$84,590	$70,327	(17%)
DPL	$90,865	$76,235	(16%)
JCPL	$78,499	$76,772	(2%)
Met-Ed	$75,704	$67,456	(11%)
PECO	$77,906	$65,597	(16%)
PENELEC	$83,444	$79,677	(5%)
Pepco	$94,523	$80,244	(15%)
PPL	$72,149	$65,412	(9%)
PSEG	$75,392	$69,695	(8%)
RECO	$71,014	$73,509	4%
PJM	$78,248	$66,735	(15%)

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is under the direction of PJM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 7-3 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year)

Zone	2012 (Jan-Sep)	2013 (Jan-Sep)	Change in 2013 from 2012
AECO	$14,772	$38,078	158%
AEP	$24,201	$41,428	71%
AP	$35,621	$72,369	103%
ATSI	$30,573	$61,682	102%
BGE	$16,708	$41,867	151%
ComEd	$42,579	$60,913	43%
DAY	$25,316	$76,092	201%
DEOK	$21,046	$67,673	222%
DLCO	$34,152	$35,642	4%
Dominion	$11,633	$37,164	219%
DPL	$19,940	$44,526	123%
JCPL	$15,697	$39,381	151%
Met-Ed	$18,897	$30,650	62%
PECO	$16,774	$34,824	108%
PENELEC	$34,896	$80,223	130%
Pepco	$18,182	$71,271	292%
PPL	$11,837	$33,955	187%
PSEG	$15,675	$62,725	300%
RECO	$15,229	$56,886	274%
PJM	$22,301	$51,966	133%

11 All starts associated with combined cycle units are assumed to be hot starts.

New Entrant Integrated Gasification Combined Cycle

Energy market net revenue was calculated for an IGCC plant located in the Dominion zone assuming that the IGCC plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations.

Table 7-4 PJM Energy Market net revenue for a new entrant IGCC (Dollars per installed MW-year)

Zone	2012 (Jan-Sep)	2013 (Jan-Sep)	Change in 2013 from 2012
Dominion	$12,804	$13,482	5%

New Entrant Diesel

Energy market net revenue was calculated assuming that the DS plant was economically dispatched on an hourly basis based on the real-time LMP.

Table 7-5 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): January through September 2013

Zone	2013 (Jan-Sep)
AECO	$7,369
AEP	$4,815
AP	$5,315
ATSI	$47,801
BGE	$8,068
ComEd	$4,552
DAY	$4,928
DEOK	$4,464
DLCO	$4,955
Dominion	$6,540
DPL	$7,615
JCPL	$7,710
Met-Ed	$7,142
PECO	$7,088
PENELEC	$5,631
Pepco	$7,339
PPL	$6,616
PSEG	$7,370
RECO	$7,239
PJM	$8,556

New Entrant Nuclear Plant

Energy market net revenue for a nuclear plant located in the AEP zone was calculated by assuming the unit was dispatched day ahead by PJM. The unit runs for all hours of the year.

Table 7-6 PJM Energy Market net revenue for a new entrant nuclear plant (Dollars per installed MW-year)

Zone	2012 (Jan-Sep)	2013 (Jan-Sep)	Change in 2013 from 2012
AEP	$146,910	$176,738	20%

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing wind units in the zone were generating power. Capacity revenue was calculated using a 13 percent capacity factor. Wind net revenues include both production tax credits and RECs.

Table 7-7 PJM Energy Market net revenue for a new entrant wind installation (Dollars per installed MW-year)

Zone	2012 (Jan-Sep)	2013 (Jan-Sep)	Change in 2013 from 2012
ComEd	$95,249	$103,483	9%
PENELEC	$89,490	$108,085	21%

New Entrant Solar Installation

Energy market net revenue for a solar installation located in the PSEG zone was calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing solar units in the zone were generating power. Capacity revenue was calculated using a 38 percent capacity factor. Solar net revenues include SRECs.

Table 7-8 PJM Energy Market net revenue for a new entrant solar installation (Dollars per installed MW-year)

Zone	2012 (Jan-Sep)	2013 (Jan-Sep)	Change in 2013 from 2012
PSEG	$306,837	$429,655	40%

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. The Mercury and Air Toxics Standards Rule (MATS) requires significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal emissions. The EPA has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The most recent interstate emissions rule, the Cross-State Air Pollution Rule (CSAPR), would if implemented, also require investments for some fossil-fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions. New Jersey's High Electric Demand Day (HEDD) Rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. CO_2 costs resulting from RGGI affect some unit offers in the PJM energy market. The investments required for environmental compliance have resulted in higher offers in the capacity market, and when units do not clear, in the retirement of units.

Renewable energy mandates and associated incentives by state and federal governments have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have potentially significant impacts on PJM wholesale markets.[1]

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[2] On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[3] The rule establishes a compliance deadline of April 16, 2015.

  In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter. On March 28, 2013, EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[4]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). The CAA requires each State to prohibit emissions that significantly interfere with the ability of another State to meet NAAQS.

  On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated the most recently issued rule limiting interstate emissions, the Cross-State Air Pollution Rule (CSAPR), which previously had been subject to a stay.[5] The Supreme Court granted EPA's petition for certiorari on June 24, 2013, and its review of CSAPR is pending. Meanwhile, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[6] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. The

1 For quantification of the economics of new entrant wind and solar installations, see the *2012 State of the Market Report for PJM*, Volume 2: Section 6, "Net Revenue."

2 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

3 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

4 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

5 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

6 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[7] The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (7-year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[8]

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[9] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[10]

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2013 for the 2012-2014 compliance period were an average of $2.89 per ton, above the price floor for 2013. The clearing price is equivalent to a price of $3.19 per metric tonne, the unit used in other carbon markets.

7 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495.
8 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660 (September 20, 2013).
9 N.J.A.C. § 7:27–19.
10 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

Emissions Controls in PJM Markets

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. On June 30, 2013, 69.4 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 97.6 percent of coal steam MW had some type of particulate control, and 91.3 percent of fossil fuel fired capacity in PJM had NOx emission control technology in place.

State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of September 30, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Renewable energy credits provide out of market payments to qualifying resources, primarily wind and solar. The out of market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the LMP is equal to the marginal cost of producing minus the credit received for each MWh. As the net of LMP and credits can be negative, the credits can provide an incentive to make negative energy offers. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Conclusion

Environmental requirements and renewable energy mandates at both the Federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), which, among other things, comprehensively regulates air emissions by establishing acceptable levels of and regulating emissions of hazardous air pollutants. EPA issues technology based standards for major sources and certain area sources of emissions.[11,12] EPA actions have and are expected to continue to affect the cost to build and operate generating units in PJM which in turn affects wholesale energy prices and capacity prices.

The EPA also regulates water pollution, and its regulation of cooling water intakes under section 316(b) of the Clean Water Act (CWA) affects generating plants that rely on water drawn from jurisdictional water bodies.[13]

11 42 U.S.C. § 7401 et seq. (2000).
12 EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.
13 The CWA applies to "navigable waters," which are, in turn, defined to include the "waters of the United States, including territorial seas." 33 U.S.C. § 1362(7). An interpretation of this rule has created some uncertainty on the scope of the waters subject to EPA jurisdiction, (*see Rapanos v. U.S., et al.*, 547 U.S. 715 (2006)), which the EPA continues to attempt to resolve.

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. There are at least three NESHAP rulemakings in progress that will impact operations at various classes of generating units.[14]

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[15] The rule establishes a compliance deadline of April 16, 2015.

In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter. On March 28, 2013, EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[16]

Air Quality Standards: Control of NO_x and SO_2 Emissions Allowances

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). The CAA requires each State to prohibit emissions that significantly interfere with the ability of another State to meet NAAQS.[17] The EPA has sought to promulgate default Federal rules to achieve this objective.[18]

14 For more details see the *2012 State of the Market Report for PJM*, Volume 2; Section 7, "Environmental and Renewables."
15 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).
16 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).
17 CAA § 110(a)(2)(D)(i)(I).
18 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."

On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[19] The Supreme Court granted EPA's petition for certiorari on June 24, 2013, and its review of CSAPR is pending. Meanwhile, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[20] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS)–Standards of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[21]

The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs), and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on the location of the engine (area source or major source), and the starter mechanism for the engine (compression ignition or spark ignition).

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[22] The proposed rule allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The Market Monitoring Unit objected to the proposed rule, as it had to similar provisions in a related proposed settlement released for comment, explaining that it was not required for participation by demand side resources in the PJM markets nor for reliability.[23] The final rule approves the proposed 100 hours per year exception, provided that RICE uses ultra low sulfur diesel fuel (ULSD).[24] Otherwise a 15-hour exception applies.[25] The exempted emergency demand response programs include Demand Resources in RPM.

Regulation of Greenhouse Gas Emissions

On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to EPA to determine whether greenhouse gases endanger public health and welfare.[26] On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare.[27] In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states.[28,29]

On September 20, 2013, EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[30] The standards would require advanced technologies like efficient natural gas units and efficient coal units implementing partial carbon capture and storage (CCS). The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross

19 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.
20 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, Final Rule*, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013) ("Final NESHAP RICE Rule").
21 EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295 , codified at 40 CFR Part 60 Subpart JJJJ.
22 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.
23 *See* Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012); *In the Matter of: EnerNOC, Inc., et al.*, Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).
24 Final NESHAP RICE Rule at 31-24.
25 *Id.* at 31.
26 Massachusetts v. EPA, 549 U.S. 497.
27 *See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (December 15, 2009).
28 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
29 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables.
30 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495; The President's Climate Action Plan, Executive Office of the President (June 2013); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency ("June 25, 2013); Presidential Memorandum–Power Section Caron Pollution Standards (June 25, 2013) (June 25th Presidential Memorandum").

over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[31]

Federal Regulation of Environmental Impacts on Water

On March 28, 2011, the EPA issued a proposed rule intended to ensure that the location, design, construction, and capacity of cooling water intake structures reflects the best technology available (BTA) for minimizing adverse environmental impacts, as required under Section 316(b) of the CWA.[32] A settlement in a Federal Court, as modified, obligates the EPA to issue a final rule no later than November 4, 2013.[33,34]

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules.

New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[35] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[36,37]

Table 8-1 shows the HEDD emissions limits applicable to each unit type. Emissions limits for coal units became effective December 15, 2012.[38] Emissions limits for other unit types will become effective May 1, 2015.[39]

Table 8-1 HEDD maximum NO_X emission rates[40]

Fuel and Unit Type	Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple cycle gas CT	1.00
Simple cycle oil CT	1.60
Combined cycle gas CT	0.75
Combined cycle oil CT	1.20
Regenerative cycle gas CT	0.75
Regenerative cycle oil CT	1.20

State Regulation of Greenhouse Gas Emissions

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[41,42]

Table 8-2 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions and additional auctions for the 2012-2014 compliance period held as of December 31, 2012. Prices for auctions held in the first nine months of 2013 for the 2012-2014 compliance period were from \$2.80 to \$3.21 per allowance (equal to one ton of CO_2), which is

31 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660 (September 20, 2013).
32 *EPA, National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, Proposed Rule*, Docket No. EPA-HQ-OW-2008-0667, 76 Fed. Reg. 22174 (April 20, 2011) (Cooling Water Proposed Rule).
33 Settlement Agreement among the United States Environmental Protection Agency, Plaintiffs in Cronin, et al. v. Reilly, 93 Civ. 314 (LTS) (SDNY), and Plaintiffs in Riverkeeper, et al. v. EPA, 06 CIV. 12987 (PKC) (SDNY), dated November 22, 2010, *modified*, Second Amendment to Settlement Agreement among the Environmental Protection Agency, Plaintiffs in Cronin, et al. v. Reilly, dated July 17, 2012; Third Amendment to Settlement Agreement among the Environmental Protection Agency, the Plaintiffs in Conin, et al. v. Reilly, 93 Civ. 314 (LTS) (SDNY), and the Plaintiffs in Riverkeeper, et al. v. EPA, 06 Civ. 12987 (PKC) (SDNY).
34 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."
35 N.J.A.C. § 7:27-19.
36 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).
37 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."
38 N.J.A.C. § 7:27-19.4.
39 N.J.A.C. § 7:27-19.5.
40 Regenerative cycle CTs are combustion turbines that recover heat from its exhaust gases and uses that heat to preheat the inlet combustion air which is fed into the combustion turbine.
41 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <*http://www.rggi.org/design/regulations*>.
42 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."

above the current price floor for RGGI auctions.[43] The RGGI clearing prices ranged from $1.86 to $1.93 per ton from June 2010 through December 2012. In 2013, the clearing price in June 2013 rose to to $3.21 per ton, the highest price since June 2009. The average spot price the first nine months of 2013 for a 2012-2014 compliance period allowance was $2.98 per ton, $0.96 higher than the average of the first nine months of 2012. Monthly average spot prices for the 2012-2014 compliance period ranged from $1.99 per ton in January to $3.42 per ton in April. Table 8-3 converts the RGGI CO_2 clearing prices and quantities to metric tonnes and corresponding prices per metric tonne for comparison to other CO_2 markets.

Table 8-2 RGGI CO_2 allowance auction prices and quantities in short tons: 2009-2011 and 2012-2014 Compliance Periods[44]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000
September 7, 2011	$1.89	42,189,685	7,847,000
December 7, 2011	$1.89	42,983,482	27,293,000
March 14, 2012	$1.93	34,843,858	21,559,000
June 6, 2012	$1.93	36,426,008	20,941,000
September 5, 2012	$1.93	37,949,558	24,589,000
December 5, 2012	$1.93	37,563,083	19,774,000
March 13, 2013	$2.80	37,835,405	37,835,405
June 5, 2013	$3.21	38,782,076	38,782,076
September 4, 2013	$2.67	38,409,043	38,409,043

43 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

44 See "Regional Greenhouse Gas Initiative: Auction Results," <*http://www.rggi.org/market/co2_auctions/results*> (Accessed July 15, 2013).

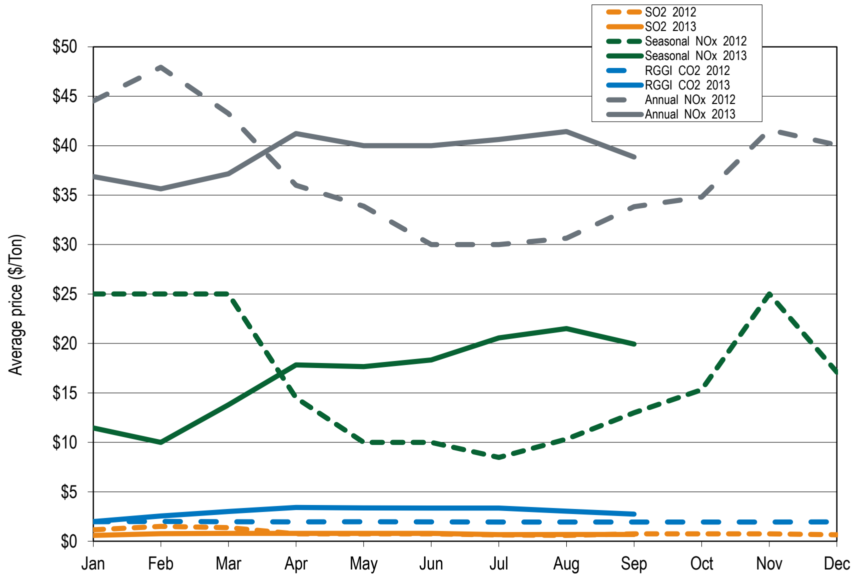
Table 8-3 RGGI CO_2 allowance auction prices and quantities in metric tonnes: 2009-2011 and 2012-2014 Compliance Periods[45]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.38	11,399,131	11,399,131
December 17, 2008	$3.73	28,581,678	28,581,678
March 18, 2009	$3.87	28,588,815	28,588,815
June 17, 2009	$3.56	28,020,786	28,020,786
September 9, 2009	$2.41	25,772,169	25,772,169
December 2, 2009	$2.26	25,937,960	25,937,960
March 10, 2010	$2.28	36,842,967	36,842,967
June 9, 2010	$2.07	36,909,352	36,909,352
September 10, 2010	$2.05	41,363,978	31,213,514
December 1, 2010	$2.05	39,166,486	22,457,365
March 9, 2011	$2.08	38,097,972	38,097,972
June 8, 2011	$2.08	38,132,781	11,373,378
September 7, 2011	$2.08	38,273,849	7,118,681
December 7, 2011	$2.08	38,993,970	24,759,800
March 14, 2012	$2.13	31,609,825	19,558,001
June 6, 2012	$2.13	33,045,128	18,997,361
September 5, 2012	$2.13	34,427,270	22,306,772
December 5, 2012	$2.13	34,076,665	17,938,676
March 13, 2013	$3.09	34,323,712	34,323,712
June 5, 2013	$3.54	35,182,518	35,182,518
September 4, 2013	$2.94	34,844,108	34,844,108

Figure 8-1 shows average, daily settled prices for NO_X and SO_2 emissions within PJM. In the first nine months of 2013, NO_X prices were 6.6 percent higher than in 2012. SO_2 prices were 20.3 percent lower in the first nine months of 2013 than in 2012. Figure 8-1 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware and Maryland.

45 See "Regional Greenhouse Gas Initiative: Auction Results," <*http://www.rggi.org/market/co2_auctions/results*> (Accessed July 15, 2013).

Figure 8-1 Spot monthly average emission price comparison: 2012 and 2013



Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of June 30, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2023. As shown in Table 8-4, New Jersey will require 22.5 percent of load to be served by renewable resources in 2023, the most stringent standard of all PJM jurisdictions. Typically, renewable generation earns renewable energy credits (also known as alternative energy credits), or RECs, when they generate. These RECs are bought by utilities and load serving entities to fulfill the requirements for renewable generation. Standards for renewable portfolios differ from jurisdiction to jurisdiction. For example, Illinois only requires utilities to purchase renewable energy credits, while Pennsylvania requires all load serving entities to purchase renewable energy credits (known as alternative energy credits in Pennsylvania).

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are out of market revenues for PJM resources and are in addition to revenues earned from the sale of the same MWh in PJM markets. Many jurisdictions allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, West Virginia allows one credit per MWh from generation from "alternative energy resources" including waste coal and pumped-storage hydroelectric, and allows two credits per MWh of electricity generated by "renewable energy resources," which include wind, solar, and run of river hydroelectric. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the Generation Attribute Tracking System (GATS), which is used by many jurisdictions to track these renewable energy credits.

Many PJM jurisdictions have also added specific requirements for the purchase of solar resources. These solar requirements are included in the standards shown in Table 8-4 but must be met by solar RECs (SRECs) only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have requirements for the proportion of load served by solar units by 2023.[46] Indiana, Michigan, Virginia, and West Virginia have no specific solar standards. In 2013, the most stringent standard in PJM was New Jersey's, requiring that 0.75 percent of load be served by solar resources. As Table 8-5 shows, by 2023, the most stringent standard will be New Jersey's which requires that at least 3.65 percent of load be served by solar.

Table 8-4 Renewable standards of PJM jurisdictions to 2023[47,48]

Jurisdiction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%
Illinois	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%
Indiana	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%	20.00%	20.00%
Michigan	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%	22.50%	22.50%
North Carolina	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%
Ohio	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%
Pennsylvania	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%
Washington, D.C.	9.00%	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%
West Virginia			10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%	15.00%	15.00%

Table 8-5 Solar renewable standards of PJM jurisdictions to 2023

Jurisdiction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%
Illinois	0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.25%	0.35%	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%
Michigan	No Solar Standard										
New Jersey	0.75%	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%
North Carolina	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%
Pennsylvania	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.50%	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%
West Virginia	No Solar Standard										

46 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the solar requirement.
47 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.
48 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.

Table 8-6 Additional renewable standards of PJM jurisdictions to 2023

Jurisdiction		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Illinois	Wind Requirement	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518	2,928	3,433
North Carolina	Swine Waste	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	700	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%

Some PJM jurisdictions have also added other specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 8-6 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind farms, with 5.25 percent of load served in 2013 escalating to 15.38 percent in 2023. Maryland, New Jersey, Pennsylvania, and Washington D.C. all have "Tier 2" or "Class 2" standards, which allow specific technology types, such as waste coal units in Pennsylvania, to qualify for renewable energy credits.[49] North Carolina also requires a certain amount of power generated using swine waste and poultry waste to fulfill their renewable portfolio standards (Table 8-6).

PJM jurisdictions include various methods for complying with required renewable portfolio standards. If an LSE is unable to comply with the renewable portfolio standards required by the LSE's jurisdiction, LSEs may make alternative compliance payments, with varying standards. These alternative compliance payments are a way to make up any shortfall between the RECs required by the state and those the LSE actually purchased. In New Jersey, solar alternative compliance payments are $641 per MWh.[50] Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO. Compliance methods differ from jurisdiction to jurisdiction. For example, Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. Alternative resources include solar, wind energy, organic biomass, and hydro power not requiring new construction. Burning waste wood, garbage, or other forms of solid waste do not qualify as alternative resources. Table 8-7 shows the alternative compliance standards in PJM jurisdictions, where such standards exist. These alternative compliance methods can have a significant impact on the traded price of RECs.

Table 8-7 Renewable alternative compliance payments in PJM jurisdictions: 2013

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$2.16		
Indiana	Voluntary standard		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$641.00
North Carolina	No specific penalties		
Ohio	$45.00		$350.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

49 Pennsylvania Tier II credits includes energy derived from waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, generation from wood pulping process, and integrated combined coal gasification technology.

50 See "New Jersey Renewables Portfolio Standard," <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0> (Accessed July 1, 2013).

Table 8-8 shows renewable generation by jurisdiction and resource type in the first nine months of 2013. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind units account for 11,289.4 GWh of 19,322.1 Tier I GWh, or 58.4 percent, in the PJM footprint. As shown in Table 8-8, 39,358.2 GWh were generated by resources that were renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 49.1 percent. Landfill gas, solid waste, and waste coal were 16,847.8 GWh of renewable generation or 42.8 percent of the total Tier I and Tier II.

Table 8-8 Renewable generation by jurisdiction and renewable resource type (GWh): January through September, 2013

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	81.6	0.0	0.0	0.0	0.0	0.0	0.0	81.6	163.2
Illinois	121.1	0.0	0.0	0.0	0.0	0.0	4,218.1	4,339.2	4,339.2
Indiana	0.0	0.0	34.2	0.0	0.0	0.0	2,333.3	2,367.5	2,367.5
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	77.5	0.0	1,357.0	50.4	709.6	0.0	360.5	1,845.3	2,554.9
Michigan	16.5	0.0	48.0	0.0	0.0	0.0	0.0	64.5	64.5
New Jersey	249.8	409.2	16.6	180.3	1,058.6	0.0	6.5	453.1	1,920.9
North Carolina	0.0	0.0	520.8	0.0	0.0	0.0	0.0	520.8	520.8
Ohio	252.0	0.0	157.3	0.7	0.0	0.0	743.0	1,152.9	1,152.9
Pennsylvania	749.9	1,406.0	2,218.5	1.1	1,195.8	7,379.1	2,527.5	5,497.0	15,477.9
Tennessee	0.0	0.0	0.0	0.0	242.7	0.0	0.0	0.0	242.7
Virginia	316.3	3,244.2	603.5	0.0	1,037.1	2,578.5	0.0	919.8	7,779.5
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	6.4	0.0	973.4	0.0	0.0	775.5	1,100.6	2,080.3	2,855.8
Total	1,871.1	5,059.4	5,929.2	232.4	4,243.7	10,733.0	11,289.4	19,322.1	39,358.2

Table 8-9 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types.[51] This capacity includes various coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits. West Virginia has the largest amount of renewable capacity in PJM, 10,027.6 MW, or 26.7 percent of the total renewable capacity. West Virginia allows coal technology, coal bed methane, waste coal and fuel produced by a coal gasification facility to be counted as alternative energy resources. New Jersey has the largest amount of solar capacity in PJM, 186.8 MW, or 75.4 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,707.6 MW, or 56.6 percent of the total wind capacity.

Table 8-9 PJM renewable capacity by jurisdiction (MW), on September 30, 2013

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,835.3	13.8	0.0	0.0	0.0	0.0	0.0	0.0	1,857.2
Illinois	0.0	78.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	2,454.4	2,553.3
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,253.2	1,261.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	510.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	580.0
Maryland	60.0	28.7	129.0	31.9	0.0	581.0	40.1	109.0	0.0	120.0	1,099.8
Michigan	0.0	4.8	0.0	0.0	0.0	11.8	0.0	0.0	0.0	0.0	16.6
New Jersey	0.0	85.5	0.0	0.0	400.0	5.0	186.8	189.1	0.0	7.5	873.9
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	94.0	0.0	0.0	409.0
Ohio	5,021.8	52.3	125.5	225.0	0.0	178.0	1.1	0.0	0.0	500.0	6,103.7
Pennsylvania	35.0	222.0	2,370.7	0.0	1,505.0	682.3	18.0	247.0	1,422.2	1,365.6	7,867.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	63.0	124.8	80.0	7.0	3,588.0	457.1	2.7	215.0	0.0	0.0	4,537.6
West Virginia	8,539.0	2.0	450.0	0.0	0.0	243.1	0.0	0.0	130.0	663.5	10,027.6
PJM Total	14,228.8	607.1	4,990.5	277.7	5,493.0	2,551.5	248.8	924.1	1,552.2	6,549.2	37,422.8

51 PJM GATS.

Table 8-10 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS. This includes solar capacity of 1,354.3 MW of which 895.8 MW is in New Jersey. These resources can also earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. All capacity shown in Table 8-10 is registered in PJM GATS, and may sell renewable energy credits through PJM EIS. Some of this capacity is located in jurisdictions outside PJM, but that may qualify for specific renewable energy credits in some jurisdictions. This includes both behind-the-meter generation located inside PJM, and generation connected to other RTOs outside PJM.

Table 8-10 Renewable capacity by jurisdiction, non-PJM units registered in GATS[52,53] (MW), on September 30, 2013

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	2.1	48.8
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	60.0
Illinois	0.0	6.6	91.8	0.0	0.0	0.0	34.5	0.0	302.5	435.4
Indiana	0.0	0.0	49.7	0.0	679.1	0.0	1.2	0.0	0.0	730.0
Kentucky	600.0	2.0	16.0	0.0	0.0	0.0	0.6	88.0	0.0	706.6
Maryland	0.0	0.0	7.0	0.0	0.0	0.0	95.2	1.2	0.3	103.7
Michigan	55.0	0.0	1.6	0.0	0.0	0.0	0.3	0.0	0.0	56.9
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	39.9	0.0	0.0	23.3	895.8	0.0	0.4	959.4
New York	0.0	146.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	147.1
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	8.0
Ohio	0.0	1.0	39.8	52.6	67.0	1.0	85.1	109.3	17.4	373.2
Pennsylvania	0.0	37.0	40.6	4.8	86.2	0.3	170.9	0.0	3.2	342.9
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	5.9	318.1	0.0	351.4
West Virginia	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	0.0	1.7
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	7.7	0.0	0.0	7.7
Total	655.0	214.8	301.1	57.4	832.4	24.6	1,354.3	621.2	472.0	4,532.8

52 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.
53 See "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed July 15, 2013).

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. Many PJM units burning fossil fuels have installed emission control technology.

Coal and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low to negligible SO_2 emission rates. Many coal steam units in PJM have installed FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units. Of the current 81,452.4 MW of coal steam capacity in PJM, 55,890.3 MW of capacity, 68.6 percent, has some form of FGD technology. Table 8-11 shows SO_2 emission controls by unit type, of fossil fuel units in PJM.[54]

Table 8-11 SO_2 emission controls (FGD) by unit type (MW), as of September 30, 2013

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	55,890.3	25,562.1	81,452.4	68.6%
Combined Cycle	0.0	27,563.3	27,563.3	0.0%
Combustion Turbine	0.0	32,322.1	32,322.1	0.0%
Diesel	0.0	371.1	371.1	0.0%
Non-Coal Steam	0.0	8,735.4	8,735.4	0.0%
Total	55,890.3	94,554.0	150,444.3	37.2%

NO_x emission control technology is used by nearly all fossil fuel unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NO_x controls. Of current fossil fuel units in PJM, 137,192.6 MW, 91.2 percent, of 150,444.3 MW of capacity in PJM, have emission controls for NO_x. Table 8-12 shows NO_x emission controls by unit type in PJM. While most units in PJM have NO_x emission controls, many of these controls will likely need to be upgraded in order to meet each state's emission compliance standards. Future NO_x compliance standards will require SCRs or SCNRs for coal steam units, as well as SCRs or water injection technology for HEDD combustion turbine units.

Table 8-12 NO_x emission controls by unit type (MW), as of September 30, 2013

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	78,694.8	2,757.6	81,452.4	96.6%
Combined Cycle	27,362.3	201.0	27,563.3	99.3%
Combustion Turbine	26,764.7	5,557.4	32,322.1	82.8%
Diesel	0.0	371.1	371.1	0.0%
Non-Coal Steam	4,370.8	4,364.6	8,735.4	50.0%
Total	137,192.6	13,251.7	150,444.3	91.2%

Most coal steam units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter in coal steam units. In PJM, 79,568.4 MW, 97.7 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 8-13 shows particulate emission controls by unit type in PJM. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many of these controls will need to be upgraded in order to meet each state's emission compliance standards. Future particulate compliance standards will require baghouse technology or a combination of an FGD and SCR to meet EPA regulations, which many coal steam units have not installed.

Table 8-13 Particulate emission controls by unit type (MW), as of September 30, 2013

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	79,568.4	1,884.0	81,452.4	97.7%
Combined Cycle	0.0	27,563.3	27,563.3	0.0%
Combustion Turbine	0.0	32,322.1	32,322.1	0.0%
Diesel	0.0	371.1	371.1	0.0%
Non-Coal Steam	3,047.0	5,688.4	8,735.4	34.9%
Total	82,615.4	67,828.9	150,444.3	54.9%

54 See "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed July 15, 2013)

Fossil fuel fired units in PJM emit multiple pollutants, including CO_2, SO_2, and NO_x. Table 8-14 shows the estimated emissions from units in PJM in the first nine months of 2013. It is estimated that over 323 million tons of CO_2, 1.2 million tons of SO_2, and 599 thousand tons of NO_x were emitted in the first nine months of 2013 by PJM units.

Table 8-14 CO_2, SO_2, NO_x emissions by month (tons), by PJM units, January through September 2013

	Tons of CO_2	Tons of SO_2	Tons of NO_x
January	37,228,219.6	134,864.3	70,054.9
February	34,317,804.9	111,597.2	64,118.8
March	35,202,337.6	124,634.3	65,220.0
April	29,674,417.2	117,490.4	55,220.0
May	31,892,446.9	104,075.3	58,020.0
June	36,950,754.6	136,733.2	67,620.4
July	43,908,563.3	195,781.2	81,327.6
August	39,182,723.1	161,062.7	72,095.7
September	35,310,555.1	142,389.6	65,215.9
Total	323,667,822.2	1,228,628.1	598,893.2

Wind Units

Table 8-15 shows the capacity factor of wind units in PJM. In the first nine months of 2013, the capacity factor of wind units in PJM was 26.7 percent. Wind units that were capacity resources had a capacity factor of 26.7 percent and an installed capacity of 4,888 MW. Wind units that were classified as energy only had a capacity factor of 26.9 percent and an installed capacity of 1,476 MW. Wind capacity in RPM is derated to 13 percent of nameplate capacity for the Capacity Market, and energy only resources are not included in the Capacity Market.[55]

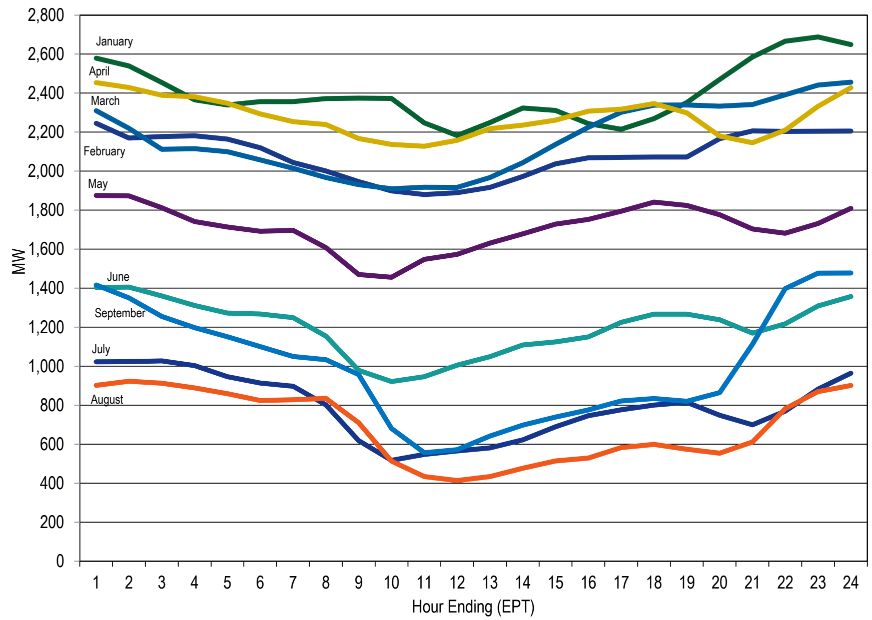
55 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.

Table 8-15 Capacity factor of wind units in PJM: January through September 2013[56]

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Installed Capacity (MW)
Energy-Only Resource	26.9%	NA	1,476
Capacity Resource	26.7%	146.7%	4,888
All Units	26.7%	146.7%	6,364

Figure 8-2 shows the average hourly real time generation of wind units in PJM, by month. The highest average hour, 2,688.8 MW, occurred in January, and the lowest average hour, 413.6 MW, occurred in August. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-2 Average hourly real-time generation of wind units in PJM: January through September 2013



56 Capacity factor does not include external resources which only offer in the DA market. Capacity factor is calculated based on online date of the resource. Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

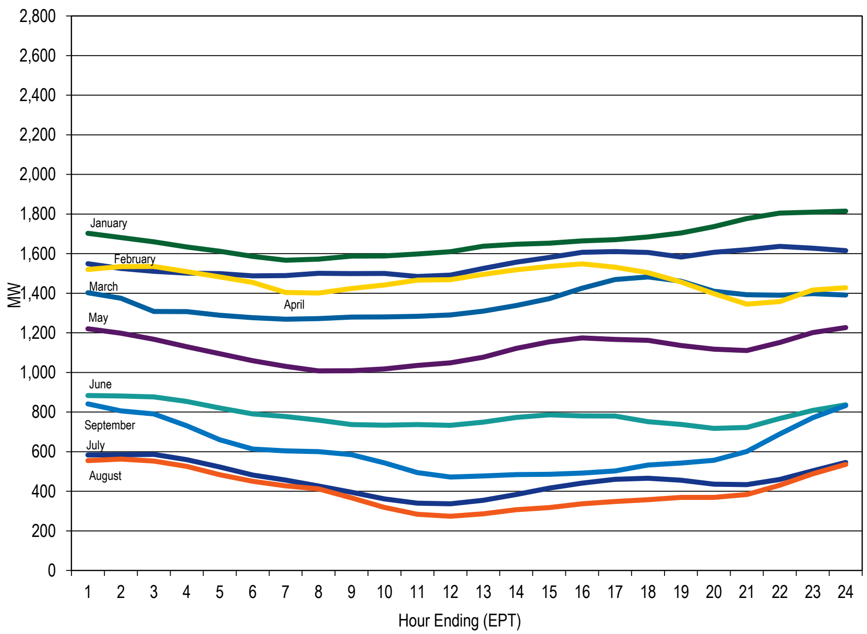
Table 8-16 shows the generation and capacity factor of wind units in each month of 2012 and the first nine months of 2013.

Table 8-16 Capacity factor of wind units in PJM by month, 2012 and January through September 2013

	2012		2013	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,608,349.8	41.9%	1,784,359.3	40.3%
February	1,167,011.9	32.4%	1,397,468.3	35.4%
March	1,416,278.0	35.6%	1,606,248.3	36.5%
April	1,345,643.3	34.7%	1,639,590.9	37.8%
May	885,583.1	21.6%	1,271,272.4	28.5%
June	882,597.0	22.2%	862,532.2	19.8%
July	546,676.9	13.3%	588,174.8	13.4%
August	415,544.2	10.1%	510,448.5	12.0%
September	677,039.5	16.9%	719,196.4	16.7%
October	1,213,664.0	27.7%		
November	1,022,628.8	22.9%		
December	1,452,588.7	31.1%		
Annual	12,633,605.2	25.7%	10,379,291.1	26.7%

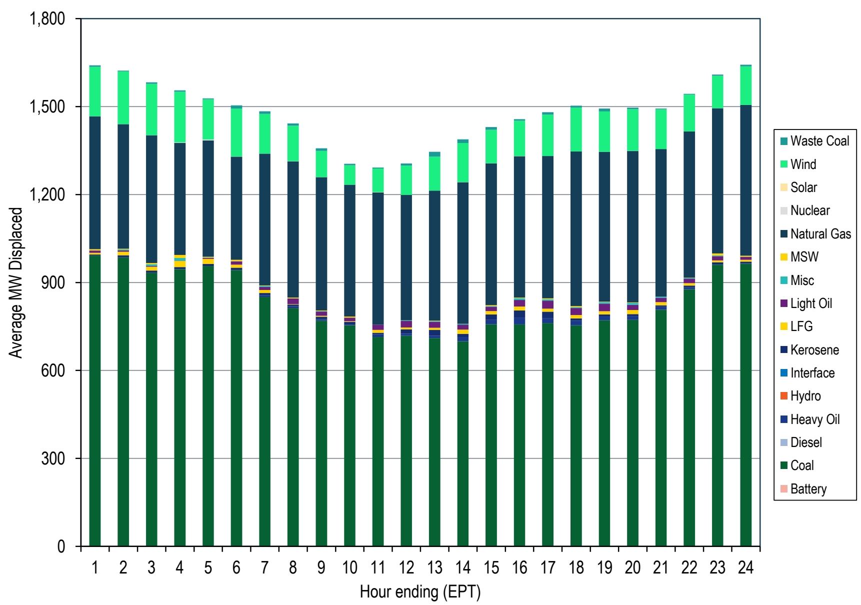
Wind units that are capacity resources are required, like all capacity resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market. In addition, the owners of wind resources have the flexibility to offer the non-capacity related wind energy at their discretion. Figure 8-3 shows the average hourly day-ahead generation offers of wind units in PJM, by month. The hourly day-ahead generation offers of wind units in PJM may vary.

Figure 8-3 Average hourly day-ahead generation of wind units in PJM: January through September 2013



Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 8-4 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation through the first nine months of 2013. Figure 8-4 shows potentially displaced marginal unit MW by fuel type in January through September 2013. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

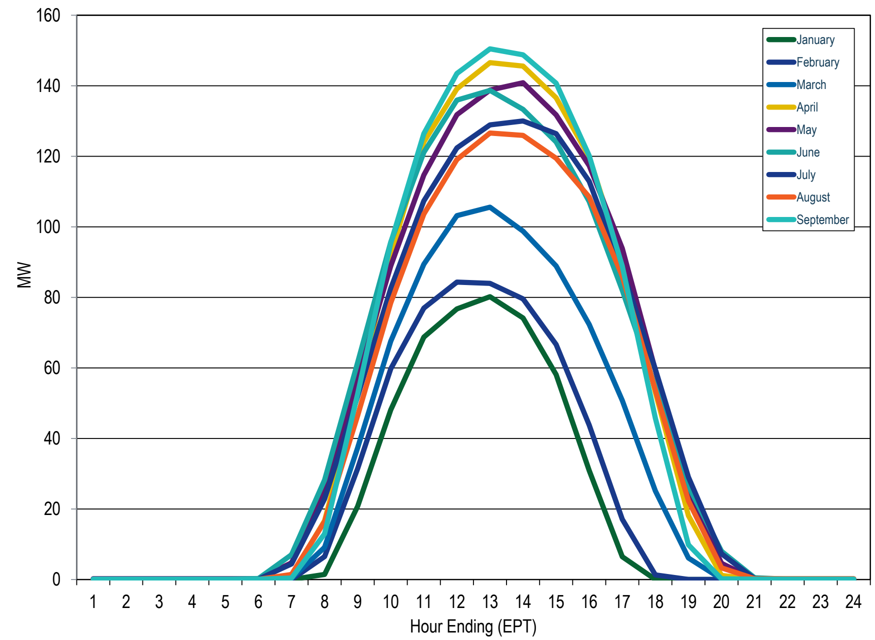
Figure 8-4 Marginal fuel at time of wind generation in PJM: January through September 2013



Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-5 shows the average hourly real time generation of solar units in PJM, by month. On average, solar generation was highest in September, the month with the highest average hour, 150.5 MW, compared to 248.8 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-5 Average hourly real-time generation of solar units in PJM: January through September 2013



Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and non-market balancing authorities.

Overview

Interchange Transaction Activity

- **East Kentucky Power Cooperative (EKPC).** On June 1, 2013, East Kentucky Power Cooperative was integrated into PJM. This integration eliminated the EKPC Interface. The integration did not result in any changes to interface pricing points.
- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first nine months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in January through August, and a net exporter of energy in September.[1] During the first nine months of 2013, the real-time net interchange of 4,706.7 GWh was greater than net interchange of 2,152.5 GWh in the first nine months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first nine months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. During the first nine months of 2013, the total day-ahead net interchange of -12,727.7 GWh was greater than net interchange of -5,824.8 GWh during the first nine months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2013, gross imports in the Day-Ahead Energy Market were 150.8 percent of gross imports in the Real-Time Energy Market (403.2 percent during the first nine months of 2012), gross exports in the Day-Ahead Energy Market were 218.5 percent of the gross exports in the Real-Time Energy Market (447.5 percent during the first nine months of 2012).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at eleven of PJM's 17 interface pricing points eligible for real-time transactions.[2]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead.
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first nine months of 2013, up-to congestion transactions had net exports at seven of PJM's 19 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in 47.0 percent of hours in the first nine months of 2013.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 53.1 percent of the hours in the first nine months of 2013.

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[3] The average hourly flow during the first nine months of 2013 was -354 MW.[4] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 69.5 percent of the hours in the first nine months of 2013.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[5] The average hourly flow during the first nine months of 2013 was -127 MW.[6] The direction of flows was consistent with price differentials in 65.8 percent of the hours in the first nine months of 2013.

- **Hudson DC Line.** The Hudson direct current (DC) line began commercial operation on June 3, 2013. The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM and NYISO. While the Hudson DC line is a bidirectional line, power flows will only be from PJM to New York. In the first four months of operations, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus.[7] The average hourly flow during the first four months of operation was -22 MW.[8] The direction of flows was consistent with price differentials in 60.9 percent of the hours between June 3, 2013 and September 30, 2013.

3 In the first nine months of 2013, there were 1,128 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $42.62 while the NYISO LMP at the Neptune Bus during non-zero flows was $64.19, a difference of $21.57.
4 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -428 MW.
5 In the first nine months of 2013, there were 1,351 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $41.23 while the NYISO LMP at the Neptune Bus during non-zero flows was $48.95, a difference of $7.72.
6 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Linden VFT line was -161 MW.
7 In its four months of operation, there were 2,987 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $48.65 while the NYISO LMP at the Hudson Bus during non-zero flows was $55.00, a difference of $6.35.
8 The average hourly flow during the first four months of operations, ignoring hours with no flow, on the Hudson line was -120 MW.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at one or more specific interfaces.

  For the first nine months of 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh. For the first nine months of 2012, net scheduled interchange was 1,051 GWh and net actual interchange was 801 GWh, a difference of 251 GWh. This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 45 TLRs of level 3a or higher in the first nine months of 2013, compared to 29 TLRs issued in the first nine months of 2012.

- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 105,472 bids per day, with an average cleared volume of 1,221,114 MWh per day, in the first nine months of 2013, compared to an average of 58,273 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012. (Figure 9-13).

- **Elimination of Ontario Interface Pricing Point.** The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing. Because 5,022 GWh of the 5,045 GWh of net transactions between PJM and IESO wheeled through MISO during the first nine months of 2013, (see Table 9-22), the MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority until the stakeholder process determines an alternative approach to pricing these transactions.

- **PJM and NYISO Coordinated Interchange Transaction Proposal.** The Coordinated Transaction Scheduling (CTS) proposal provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated. The evaluation will be based on the forward-looking prices as determined by PJM's Intermediate Term Security Constrained Economic Dispatch tool (ITSCED) and the NYISO's Real Time Commitment (RTC) tool.

  CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve payments are applied and CTS transactions are optional, there is no reason not to proceed with the development of the CTS proposal. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be addressed to improve the efficiency of interchange transaction pricing at the PJM/NYISO seam. Minimizing this time lag is more likely to improve pricing efficiency at the PJM/NYISO border than the CTS transaction approach.

- **Elimination of Sources and Sinks.** The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[9] On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction. The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The MMU continues to recommend that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

9 See "Meeting Minutes, "Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> (Accessed October 9, 2013).

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non-market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non-market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non-market areas do not include these features. The market areas are extremely transparent and the non-market areas are not transparent.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first nine months of 2013, including evolving transaction patterns, economics and issues. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows began to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased, reducing the day-ahead gross import and export volumes. While the gross import and export volumes in the Day-Ahead Market have decreased, the net direction of power flows has remained predominantly in the export direction.

In the first nine months of 2013, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for 53.0 percent of the hours for transactions between PJM and MISO and for 46.9 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by relying on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely as possible to the expected actual power flows would result in a more economic dispatch of the entire Eastern Interconnection.

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load which can create loop flows and inaccurate pricing for transactions. The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create business rules that prevent sham scheduling among and between the RTO/ISO markets.

The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the operation of the PJM Day-Ahead Market and charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges. The level of the fee should be determined based on the method defined in the State of the Market Report.[10]

10 See the *2013 Quarterly State of the Market Report for PJM: January to September*, Section 4, "Operating Reserves."

There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast). The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the integration, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO. The NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy market to facilitate the long term day-ahead positions created at the NIPSCO interface prior to the integration.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[11] After the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. The grandfathered agreements for the Southeast interface pricing point have expired. The Southeast interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy market to facilitate the long term day-ahead positions created prior to the consolidation of the Southeast and Southwest interface pricing points.

The MMU recommends that PJM no longer accept long term positions of any kind at the NIPSCO and Southeast interface pricing points and to eliminate these interface pricing points from the Day-Ahead and Real-Time Energy Markets.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[12] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

The MMU continues to recommend that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

Interchange Transaction Activity

Aggregate Imports and Exports

During the first nine months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in January through August, and a net exporter of energy in September (Figure 9-1).[13] During the first nine months of 2013, the total real-time net interchange of 4,706.7 GWh was greater than the net interchange of 2,152.5 GWh during the first nine months of 2012. During the first nine months of 2013, the peak month for net importing interchange was July, 1,464.4 GWh; in 2012 it was May, 798.4 GWh. Gross monthly export volumes during the first nine months of 2013 averaged 3,257.1 GWh compared to 3,639.6 GWh for the first nine months of 2012, while gross monthly imports during the first nine months of 2013 averaged 3,780.1 GWh compared to 3,878.7 GWh during the first nine months of 2012.

During the first nine months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 9-1). During the first nine months of 2013, the total day-ahead net interchange of -12,727.7 GWh was greater than the net interchange of -5,824.8 GWh during the first nine months of 2012. During the first nine months of 2013, the peak month for net exporting interchange was January, -2,602.8 GWh; in 2012 it was

11 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (Accessed October 10, 2013).

12 See Docket Nos. ER12-1338-000 and ER12-1343-000.

13 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

January, -1,847.5 GWh. Gross monthly export volumes during the first nine months of 2013 averaged 7,115.8 GWh compared to 16,287.0 GWh for the first nine months of 2012, while gross monthly imports during the first nine months of 2013 averaged 5,701.6 GWh compared to 15,639.8 GWh during the first nine months of 2012.

The large decreases in gross import and export volumes in the Day-Ahead Energy Market were the result of the rule change on November 1, 2012, which permitted up-to congestion transactions to be submitted between two internal buses. Prior to the rule change, up-to congestion transactions were required to have the source at an interface (modeled as an import) or the sink at an interface (modeled as an export).[14]

Figure 9-1 shows the impact of net import and export up-to congestion transactions on the overall net Day-Ahead Market interchange. The import, export and net interchange volumes include fixed, dispatchable and up-to congestion transaction totals. The up-to congestion net volume (as represented by the line on the chart) shows the net up-to congestion transaction volume. The net interchange volume under the line in Figure 9-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

In the first nine months of 2013, import up-to congestion transactions accounted for 70.7 percent of all scheduled import MW transactions, export up-to congestion transactions accounted 66.2 percent of all scheduled export MW transactions and net up-to congestion transactions accounted for 48.1 percent of the net interchange volume in the Day-Ahead Market. The average number of import and export up-to congestion bids that had approved MWh in the Day-Ahead Market decreased to 9,741 bids per day, with an average cleared volume of 274,769 MWh per day, in the first nine months of 2013, compared to an average of 22,392 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012.

The average number of up-to congestion bids, including internal up-to congestion transactions, that had approved MWh in the Day-Ahead Market increased to 37,762 bids per day, with an average cleared volume of 1,221,114 MWh per day, in the first nine months of 2013, compared to an average of 22,392 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012.

In the first nine months of 2013, gross imports in the Day-Ahead Energy Market were 150.8 percent of gross imports in the Real-Time Energy Market (403.2 percent during the first nine months of 2012), gross exports in the Day-Ahead Energy Market were 218.5 percent of gross exports in the Real-Time Energy Market (447.5 percent during the first nine months of 2012). In the first nine months of 2013, net interchange was -12,727.7 GWh in the Day-Ahead Energy Market and 4,706.7 GWh in the Real-Time Energy Market compared to -5,824.8 GWh in the Day-Ahead Energy Market and 2,152.5 GWh in the Real-Time Energy Market for the first nine months of 2012.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MW and price differences in the Day-Ahead and Real-Time Energy Markets.[15] For the first nine months of 2013, while the total day-ahead imports and exports were greater than the real-time imports and exports, the day-ahead imports net of up-to congestion transactions were less than the real-time imports, and the day-ahead exports net of up-to congestion transactions were less than real-time exports. In addition, day-ahead transactions can be offset by increment offers, decrement bids and internal bilateral transactions.

14 See *"Up-To Congestion Transaction Enhancements,"* (October 10, 2012) <https://pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-11-up-to-congestion-transactions.ashx> (Accessed October 9, 2013).

15 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: January through September, 2013

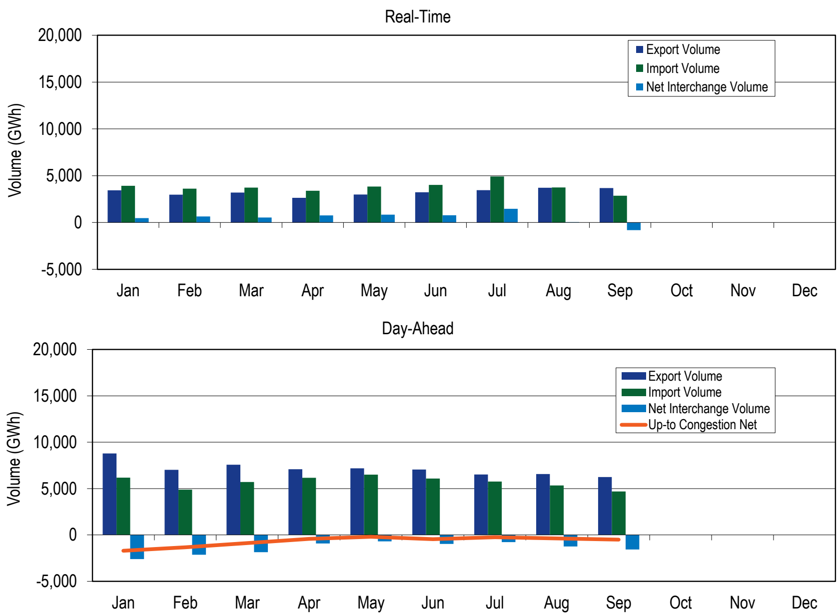
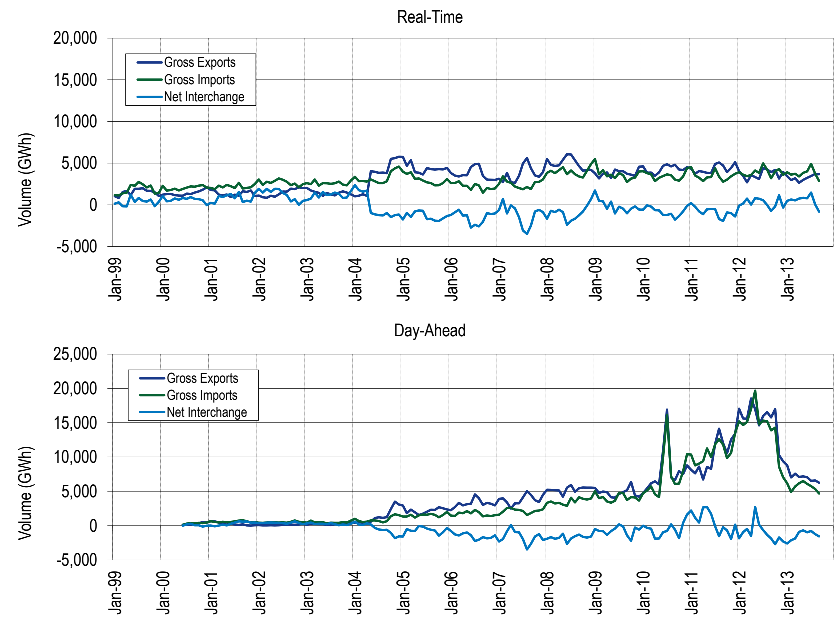


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through September, 2013. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows started to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased, reducing the day-ahead gross import and export volumes. While the gross import and export volumes in the Day-Ahead Market have decreased, the net direction of power flows has remained predominantly in the export direction.

Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January, 1999 through September, 2013



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. See Table 9-16 for a list of active interfaces during the first nine months of 2013. Figure 9-3 shows the approximate geographic location of the interfaces. In the first nine months of 2013, PJM had 21 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the

Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. Similarly, there are nine separate interfaces that make up the MISO Interface between the PJM and MISO balancing authorities. Table 9-1 through Table 9-3 show the Real-Time Market interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net interchange in the Real-Time Energy Market is shown by interface for the first nine months of 2013 in Table 9-1, while gross imports and exports are shown in Table 9-2 and Table 9-3.

In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.[16] The top three net exporting interfaces in the Real-Time Energy Market accounted for 67.3 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 24.2 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 23.6 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 19.5 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 43.9 percent of the total net PJM exports in the Real-Time Energy Market. Nine PJM interfaces had net scheduled imports, with three importing interfaces accounting for 61.2 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 32.6 percent, PJM/Tennessee Valley Authority (TVA) with 16.3 percent and PJM/Michigan Electric Coordinated System (MECS) with 12.3 percent of the net import volume.[17]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of OVEC is owned by load serving entities or their affiliates within the PJM footprint. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires delivery of approximately 70 percent of the generation output into the PJM footprint.[18] OVEC itself does not serve load, and therefore does not generally import energy. OVEC accounts for a large percentage of PJM's net interchange import volume.

16 In June, 2013, the EKPC Interface was eliminated, and the HUDS Interface was added. While there are 21 total interfaces with PJM during 2013, only 20 were active at any given time.

17 In the Real-Time Market, two PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP) and PJM/western portion of Carolina Power & Light Company (CPLW)).

Table 9-1 Real-time scheduled net interchange volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(30.6)	(38.3)	(48.4)	(33.1)	(25.3)	188.1	206.8	211.8	(52.7)	378.2
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	175.2	122.7	148.1	80.9	294.6	221.9	263.2	134.0	(49.5)	1,391.1
EKPC	(149.7)	(139.9)	(152.7)	(152.2)	(108.8)					(703.3)
LGEE	281.5	272.0	302.2	182.9	204.3	253.5	312.2	263.2	206.7	2,278.4
MEC	(484.1)	(390.8)	(158.9)	(421.4)	(509.1)	(464.2)	(492.5)	(478.1)	(465.7)	(3,864.8)
MISO	283.1	518.3	572.6	622.4	103.4	62.0	690.9	(318.8)	(442.3)	2,091.8
ALTE	(306.7)	(176.9)	(239.3)	(214.3)	(454.5)	(449.7)	(370.3)	(474.7)	(420.9)	(3,107.5)
ALTW	(9.0)	(4.5)	(3.0)	(3.8)	(25.3)	(40.2)	(1.8)	(33.8)	(17.9)	(139.1)
AMIL	181.7	153.6	181.5	150.2	170.1	12.0	340.6	(76.7)	(145.2)	967.8
CIN	253.3	285.4	349.7	272.0	129.6	350.0	376.1	315.0	165.9	2,496.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(43.4)	48.1	63.8	74.5	(29.2)	128.7	239.6	50.6	(10.8)	522.0
MECS	322.3	298.9	322.5	433.4	529.0	291.8	205.0	24.1	130.0	2,556.8
NIPS	(22.9)	(12.5)	(22.0)	(25.6)	(71.6)	(5.0)	9.3	(7.7)	(6.2)	(164.1)
WEC	(92.1)	(73.8)	(80.5)	(64.0)	(144.7)	(225.6)	(107.6)	(115.6)	(137.1)	(1,041.0)
NYISO	(1,047.1)	(1,018.0)	(1,100.9)	(313.3)	(216.5)	(608.4)	(977.3)	(897.7)	(820.5)	(6,999.7)
HUDS						(24.8)	(31.6)	(17.7)	(7.8)	(81.8)
LIND	(165.2)	(149.8)	(91.6)	(64.9)	(77.0)	(55.8)	(73.0)	(71.9)	(85.2)	(834.7)
NEPT	(270.9)	(245.9)	(239.2)	(247.1)	(102.5)	(167.8)	(409.3)	(415.2)	(223.8)	(2,321.8)
NYIS	(611.0)	(622.3)	(770.1)	(1.3)	(37.0)	(360.0)	(463.3)	(392.9)	(503.7)	(3,761.4)
OVEC	798.2	713.5	585.0	542.8	712.0	908.3	985.5	825.5	685.2	6,756.1
TVA	643.8	600.0	383.6	249.0	392.2	217.6	475.5	297.6	119.5	3,378.9
Total	470.4	639.5	530.6	757.9	846.7	778.9	1,464.4	37.5	(819.3)	4,706.7

18 See *"Ohio Valley Electric Corporation: Company Background,"* <http://www.ovec.com/OVECHistory.pdf> (Accessed October 9, 2013).

Table 9-2 Real-time scheduled gross import volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	1.4	0.1	1.6	0.0	2.0	219.4	236.8	227.4	0.0	688.6
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	225.0	190.6	157.0	137.4	320.4	265.8	301.2	202.6	70.7	1,870.7
EKPC	4.4	1.5	25.6	21.8	33.0					86.3
LGEE	299.0	272.4	302.2	186.0	205.0	255.4	318.3	264.2	223.2	2,325.6
MEC	0.2	48.2	320.6	6.2	0.0	0.0	3.9	3.3	1.1	383.7
MISO	1,026.7	971.1	1,110.5	1,199.0	1,264.4	1,193.4	1,596.0	998.0	896.6	10,255.6
ALTE	0.0	1.1	0.0	0.0	0.0	0.0	3.7	0.0	0.0	4.8
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	207.0	177.1	215.1	198.2	213.8	79.0	386.4	98.4	107.6	1,682.7
CIN	374.5	394.7	455.5	438.9	358.2	519.7	518.4	493.0	361.8	3,914.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	95.9	76.5	101.6	101.3	70.4	176.3	289.3	103.6	62.7	1,077.7
MECS	349.1	321.6	338.3	458.2	621.9	418.4	383.5	302.8	362.5	3,556.4
NIPS	0.2	0.0	0.0	2.4	0.0	0.0	14.7	0.2	1.9	19.3
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	871.0	782.0	820.7	1,037.6	857.5	895.0	984.2	914.4	834.0	7,996.5
HUDS						0.0	0.0	0.0	0.0	0.0
LIND	0.6	10.4	7.5	13.5	7.8	10.2	19.7	9.0	8.1	86.8
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	870.5	771.6	813.2	1,024.1	849.7	884.8	964.5	905.4	825.9	7,909.7
OVEC	798.3	713.5	585.1	543.8	728.4	916.1	985.6	825.5	685.2	6,781.4
TVA	689.8	630.0	399.1	261.5	431.9	265.9	493.8	313.8	146.9	3,632.7
Total	3,915.7	3,609.5	3,722.4	3,393.4	3,842.5	4,010.9	4,919.6	3,749.2	2,857.7	34,021.0

Table 9-3 Real-time scheduled gross export volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	31.9	38.4	50.0	33.1	27.3	31.3	30.0	15.7	52.7	310.3
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	49.8	67.9	8.9	56.5	25.8	43.9	37.9	68.6	120.2	479.5
EKPC	154.0	141.4	178.3	174.0	141.8					789.6
LGEE	17.5	0.4	0.0	3.1	0.7	1.8	6.1	1.1	16.5	47.2
MEC	484.4	439.0	479.6	427.6	509.1	464.2	496.4	481.4	466.8	4,248.5
MISO	743.5	452.8	537.9	576.7	1,161.0	1,131.4	905.0	1,316.7	1,338.8	8,163.8
ALTE	306.7	178.0	239.3	214.3	454.5	449.7	374.0	474.7	420.9	3,112.2
ALTW	9.0	4.5	3.0	3.8	25.3	40.2	1.8	33.8	17.9	139.1
AMIL	25.3	23.5	33.6	48.0	43.7	67.0	45.7	175.2	252.8	714.9
CIN	121.2	109.3	105.8	166.9	228.6	169.7	142.3	178.0	195.9	1,417.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	139.3	28.4	37.8	26.8	99.7	47.6	49.7	53.0	73.5	555.7
MECS	26.8	22.7	15.8	24.8	93.0	126.6	178.6	278.7	232.6	999.5
NIPS	23.0	12.5	22.0	28.0	71.6	5.0	5.4	7.8	8.1	183.4
WEC	92.1	73.8	80.5	64.0	144.7	225.6	107.6	115.6	137.1	1,041.0
NYISO	1,918.1	1,800.1	1,921.6	1,351.0	1,074.0	1,503.4	1,961.4	1,812.1	1,654.6	14,996.2
HUDS						24.8	31.6	17.7	7.8	81.8
LIND	165.8	160.3	99.1	78.5	84.8	66.1	92.7	80.9	93.3	921.5
NEPT	270.9	245.9	239.2	247.1	102.5	167.8	409.3	415.2	223.8	2,321.8
NYIS	1,481.5	1,393.9	1,583.3	1,025.4	886.6	1,244.7	1,427.8	1,298.3	1,329.7	11,671.1
OVEC	0.1	0.0	0.0	1.1	16.4	7.8	0.0	0.0	0.0	25.4
TVA	46.0	30.0	15.6	12.5	39.7	48.3	18.3	16.1	27.4	253.9
Total	3,445.3	2,970.0	3,191.9	2,635.5	2,995.8	3,232.0	3,455.2	3,711.7	3,677.0	29,314.3

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which scheduled imports or exports will flow.[19] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the

19 A market path is the scheduled path rather than the actual path on which power flows. A market path contains the generation balancing authority, all required transmission segments and the load balancing authority. There are multiple market paths between any generation and load balancing authority. Market participants select the market path based on transmission service availability and the transmission costs for moving energy from generation to load.

GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the MISO/PJM Interface based on the scheduled market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the MISO/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[20]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[21] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area and Load Control Area as specified on the NERC Tag. According to the *PJM Interface Price Definition Methodology*, dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[22] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. Table 9-17 presents the interface pricing points used for the first nine months of 2013.

20 See the *2007 State of the Market Report for PJM*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.
21 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 9, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.
22 See "PJM Interface Pricing Definition Methodology," (September 29, 2006) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx> (Accessed October 9, 2013).

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified by PJM only occasionally.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The result of such behavior can be incorrect pricing of transactions.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[23]

In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at eleven of PJM's 17 interface pricing points eligible for real-time transactions.[24] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 72.6 percent of the total net exports: PJM/MISO with 56.6 percent, and PJM/NYIS with 16.0 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 33.3 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 78.7 percent of the total

23 The MMU does not believe that it is appropriate to allow the use of the Southwest pricing point for the grandfathered transactions, and suggests that no further such agreements be entered into.
24 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

net imports: PJM/SouthIMP with 49.9 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 28.8 percent of the net import volume.

Table 9-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS						(24.8)	(31.6)	(17.7)	(7.8)	(81.8)
IMO	592.6	395.0	556.4	547.2	668.7	584.3	616.2	516.6	522.7	4,999.6
LINDENVFT	(165.2)	(149.8)	(91.6)	(64.9)	(77.0)	(55.8)	(73.0)	(71.9)	(85.2)	(834.7)
MISO	(1,015.3)	(686.3)	(699.3)	(709.9)	(1,444.8)	(1,513.8)	(1,146.5)	(1,683.6)	(1,675.8)	(10,575.4)
NEPTUNE	(270.9)	(245.9)	(239.2)	(247.1)	(102.5)	(167.8)	(409.3)	(415.2)	(223.8)	(2,321.8)
NORTHWEST	(3.6)	(3.3)	(5.9)	(5.0)	(5.5)	(2.7)	(1.2)	(0.3)	(3.9)	(31.5)
NYIS	(603.2)	(572.1)	(706.3)	62.9	28.4	(230.2)	(289.9)	(271.6)	(402.6)	(2,984.7)
OVEC	798.2	713.5	585.0	542.8	712.0	908.3	985.5	825.5	685.2	6,756.1
SOUTHIMP	1,441.6	1,472.4	1,387.4	923.1	1,306.5	1,411.2	1,909.4	1,260.0	591.9	11,703.4
CPLEIMP	0.0	0.0	0.0	0.0	0.0	219.4	230.0	222.8	0.0	672.2
DUKIMP	107.2	105.3	83.8	46.7	110.6	129.7	136.7	58.7	28.4	807.1
NCMPAIMP	68.6	31.3	19.5	22.6	95.1	61.7	62.1	48.5	17.6	427.1
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	853.8	1,100.9	1,000.4	1,480.5	930.0	545.9	9,797.0
SOUTHEXP	(303.9)	(283.9)	(255.9)	(291.0)	(238.9)	(129.7)	(95.1)	(104.2)	(220.0)	(1,922.6)
CPLEEXP	(31.3)	(33.4)	(47.6)	(32.0)	(26.7)	(30.8)	(29.7)	(15.2)	(49.7)	(296.4)
DUKEXP	(27.1)	(45.2)	(0.9)	(32.9)	(11.8)	(29.9)	(27.3)	(44.4)	(45.3)	(264.8)
NCMPAEXP	0.0	(0.1)	0.0	(0.2)	0.0	(1.5)	0.0	0.0	0.0	(1.7)
SOUTHWEST	(4.5)	(5.7)	(3.0)	(11.7)	(3.6)	(4.4)	(2.4)	(2.3)	(2.8)	(40.3)
SOUTHEXP	(241.0)	(199.6)	(204.5)	(214.2)	(196.9)	(63.1)	(35.6)	(42.3)	(122.2)	(1,319.5)
Total	470.4	639.5	530.6	757.9	846.7	778.9	1,464.4	37.5	(819.3)	4,706.7

Table 9-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS						0.0	0.0	0.0	0.0	0.0
IMO	594.6	403.2	562.5	549.8	669.9	584.7	621.6	522.0	533.1	5,041.3
LINDENVFT	0.6	10.4	7.5	13.5	7.8	10.2	19.7	9.0	8.1	86.8
MISO	204.4	196.3	309.1	277.5	215.9	74.6	250.9	110.3	116.3	1,755.4
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.7
NYIS	876.3	813.6	870.9	1,085.7	914.0	1,014.1	1,132.5	1,021.6	923.1	8,651.9
OVEC	798.3	713.5	585.1	543.8	728.4	916.1	985.6	825.5	685.2	6,781.4
SOUTHIMP	1,441.6	1,472.4	1,387.4	923.1	1,306.5	1,411.2	1,909.4	1,260.0	591.9	11,703.4
CPLEIMP	0.0	0.0	0.0	0.0	0.0	219.4	230.0	222.8	0.0	672.2
DUKIMP	107.2	105.3	83.8	46.7	110.6	129.7	136.7	58.7	28.4	807.1
NCMPAIMP	68.6	31.3	19.5	22.6	95.1	61.7	62.1	48.5	17.6	427.1
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	853.8	1,100.9	1,000.4	1,480.5	930.0	545.9	9,797.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3,915.7	3,609.5	3,722.4	3,393.4	3,842.5	4,010.9	4,919.6	3,749.2	2,857.7	34,021.0

Table 9-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS						24.8	31.6	17.7	7.8	81.8
IMO	2.0	8.2	6.1	2.6	1.3	0.4	5.3	5.4	10.3	41.7
LINDENVFT	165.8	160.3	99.1	78.5	84.8	66.1	92.7	80.9	93.3	921.5
MISO	1,219.7	882.6	1,008.4	987.4	1,660.7	1,588.4	1,397.5	1,794.0	1,792.1	12,330.8
NEPTUNE	270.9	245.9	239.2	247.1	102.5	167.8	409.3	415.2	223.8	2,321.8
NORTHWEST	3.6	3.3	5.9	5.0	5.5	2.7	1.2	1.0	3.9	32.2
NYIS	1,479.5	1,385.8	1,577.2	1,022.8	885.6	1,244.3	1,422.4	1,293.2	1,325.7	11,636.6
OVEC	0.1	0.0	0.0	1.1	16.4	7.8	0.0	0.0	0.0	25.4
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	303.9	283.9	255.9	291.0	238.9	129.7	95.1	104.2	220.0	1,922.6
CPLEEXP	31.3	33.4	47.6	32.0	26.7	30.8	29.7	15.2	49.7	296.4
DUKEXP	27.1	45.2	0.9	32.9	11.8	29.9	27.3	44.4	45.3	264.8
NCMPAEXP	0.0	0.1	0.0	0.2	0.0	1.5	0.0	0.0	0.0	1.7
SOUTHWEST	4.5	5.7	3.0	11.7	3.6	4.4	2.4	2.3	2.8	40.3
SOUTHEXP	241.0	199.6	204.5	214.2	196.9	63.1	35.6	42.3	122.2	1,319.5
Total	3,445.3	2,970.0	3,191.9	2,635.5	2,995.8	3,232.0	3,455.2	3,711.7	3,677.0	29,314.3

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[25] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow unless they are also submitted in the Real-Time Energy Market. In the Day-Ahead Energy Market,

25 Effective September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in this report.

a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up-to congestion; and dispatchable.[26]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. In Table 9-7, Table 9-8 and Table 9-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, a market participant may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM. If the market participant knows that the source of the energy in the Real-Time Market will be associated with the SouthIMP interface pricing point, they may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Market. In the interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP Interface Pricing Point, which reflects the expected power flow.

Table 9-7 through Table 9-9 show the Day-Ahead interchange totals at the individual interfaces. Net interchange in the Day-Ahead Market is shown by interface for the first nine months of 2013 in Table 9-7, while gross imports and exports are shown in Table 9-8 and Table 9-9.

In the Day-Ahead Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.[27] The top three net exporting interfaces in the Real-Time Energy Market accounted for 77.6 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 30.7 percent, PJM/MidAmerican Energy Company (MEC) with 29.6 percent, and PJM/NEPT with 17.2 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 48.9 percent of the total net PJM exports in the Day-Ahead Energy Market. The nine separate interfaces that connect PJM to MISO together represented 14.1 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interfaces had net scheduled imports, with three importing interfaces accounting for 79.8 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 63.1 percent, PJM/DUK with 11.1 percent and PJM/Michigan Electric Coordinated Systems (MECS) with 5.7 percent of the net import volume.[28]

26 See the *2010 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for details.

27 In June, 2013, the EKPC Interface was eliminated, and the HUDS Interface was added. While there are 21 total interfaces with PJM during 2013, only 20 were active at any given time.

28 In the Day-Ahead Market, two PJM interfaces had a net interchange of zero (PJM/Carolina Power and Light – Western (CPLW) and PJM/City Water Light & Power (CWLP)).

Table 9-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(33.4)	(28.5)	(41.2)	(30.5)	(24.1)	172.0	208.7	215.4	(47.1)	391.2
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	82.3	145.7	127.5	149.9	80.9	22.3	832.6
EKPC	(36.6)	(33.6)	(37.2)	(36.0)	(37.2)					(180.5)
LGEE	58.3	65.8	81.8	40.3	2.3	0.0	0.0	0.0	0.0	248.5
MEC	(483.0)	(435.7)	(477.7)	(423.0)	(484.7)	(462.9)	(463.0)	(472.9)	(454.9)	(4,157.8)
MISO	(242.1)	(52.6)	(48.7)	(34.3)	(324.7)	(302.2)	(204.9)	(419.6)	(343.7)	(1,972.8)
ALTE	(177.8)	(79.5)	(119.1)	(99.9)	(238.2)	(267.3)	(289.0)	(318.5)	(296.3)	(1,885.4)
ALTW	(7.6)	(2.5)	0.0	0.0	(2.5)	(35.8)	0.0	(24.0)	(6.8)	(79.1)
AMIL	8.7	5.2	26.3	13.5	(0.9)	(1.2)	1.9	(5.0)	(38.2)	10.3
CIN	7.9	45.9	37.1	32.3	18.3	44.4	41.6	37.1	61.9	326.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(0.9)	(5.9)	(1.6)	0.0	0.0	33.9	117.5	54.5	0.0	197.6
MECS	23.4	45.8	102.9	93.1	97.9	36.9	8.9	(55.8)	72.2	425.4
NIPS	(22.2)	(12.5)	(21.5)	(27.8)	(70.7)	0.0	0.6	0.0	(0.2)	(154.3)
WEC	(73.7)	(49.2)	(72.8)	(45.5)	(128.8)	(113.1)	(86.4)	(107.9)	(136.4)	(813.8)
NYISO	(833.6)	(874.4)	(944.3)	(459.5)	(386.6)	(707.5)	(968.7)	(910.2)	(777.0)	(6,861.8)
HUDS					(32.5)	(36.6)	(18.4)	(12.1)	(7.9)	(107.6)
LIND	(15.3)	(14.3)	(2.6)	0.1	0.0	0.1	0.0	0.0	0.0	(32.1)
NEPT	(278.5)	(255.2)	(248.7)	(253.1)	(101.5)	(193.7)	(420.0)	(425.6)	(236.7)	(2,413.1)
NYIS	(539.7)	(604.9)	(693.0)	(206.5)	(252.6)	(477.2)	(530.3)	(472.4)	(532.3)	(4,309.1)
OVEC	561.5	494.4	408.0	324.6	522.8	644.8	691.9	598.5	498.0	4,744.4
TVA	32.7	3.6	(3.6)	41.2	92.4	18.6	71.9	47.0	42.9	346.7
Total without Up-To Congestion	(898.1)	(790.9)	(987.2)	(494.9)	(494.1)	(509.7)	(514.3)	(860.9)	(1,059.5)	(6,609.5)
Up-To Congestion	(1,704.8)	(1,336.7)	(875.0)	(421.3)	(191.6)	(457.4)	(252.3)	(374.2)	(505.0)	(6,118.1)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(916.1)	(685.7)	(967.1)	(766.5)	(1,235.0)	(1,564.5)	(12,727.7)

Table 9-8 Day-Ahead scheduled gross import volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	0.0	0.0	0.0	0.0	0.0	202.5	237.7	228.5	0.0	668.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	82.3	145.7	127.5	149.9	80.9	24.2	834.6
EKPC	0.0	0.0	0.0	0.0	0.0					0.0
LGEE	58.3	65.8	81.8	40.3	2.3	0.0	0.0	0.0	0.0	248.5
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	75.2	115.2	196.6	184.4	231.6	229.4	270.8	213.2	235.3	1,751.8
ALTE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	8.7	5.2	26.3	13.5	3.9	1.9	1.9	0.0	7.9	69.5
CIN	21.5	64.2	58.4	77.7	61.9	52.0	41.6	41.5	62.7	481.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	5.6	0.0	0.0	0.0	0.0	33.9	117.5	54.5	0.0	211.6
MECS	39.3	45.8	111.9	93.1	165.8	141.6	109.2	117.1	164.6	988.6
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.6
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	726.2	650.4	717.7	768.3	601.6	726.7	755.8	749.1	696.8	6,392.6
HUDS					0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.1	9.3	2.9	0.1	0.0	0.1	0.0	0.0	0.0	12.4
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	726.2	641.1	714.8	768.2	601.6	726.6	755.8	749.1	696.8	6,380.2
OVEC	561.5	494.4	408.0	324.6	522.8	644.8	691.9	598.5	498.0	4,744.4
TVA	41.7	13.6	3.6	42.7	102.8	21.5	74.1	47.0	50.1	397.0
Total without Up-To Congestion	1,540.9	1,409.5	1,483.5	1,442.6	1,606.8	1,952.4	2,180.1	1,917.2	1,504.4	15,037.5
Up-To Congestion	4,637.9	3,481.0	4,226.5	4,728.9	4,890.0	4,135.3	3,571.1	3,422.3	3,183.9	36,276.8
Total	6,178.8	4,890.5	5,710.0	6,171.5	6,496.8	6,087.8	5,751.2	5,339.5	4,688.3	51,314.3

Table 9-9 Day-Ahead scheduled gross export volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	33.4	28.5	41.2	30.5	24.1	30.5	29.0	13.1	47.1	277.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0
EKPC	36.6	33.6	37.2	36.0	37.2					180.5
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	483.0	435.7	477.7	423.0	484.7	462.9	463.0	472.9	454.9	4,157.8
MISO	317.3	167.9	245.4	218.6	556.4	531.6	475.7	632.8	579.0	3,724.6
ALTE	177.8	79.5	119.1	99.9	238.2	267.3	289.0	318.5	296.3	1,885.4
ALTW	7.6	2.5	0.0	0.0	2.5	35.8	0.0	24.0	6.8	79.1
AMIL	0.0	0.0	0.0	0.0	4.8	3.2	0.0	5.0	46.1	59.2
CIN	13.7	18.3	21.3	45.5	43.5	7.6	0.0	4.4	0.8	155.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	6.5	5.9	1.6	0.0	0.0	0.0	0.0	0.0	0.0	14.0
MECS	15.9	0.0	9.1	0.0	67.9	104.7	100.3	172.9	92.5	563.2
NIPS	22.2	12.5	21.5	27.8	70.7	0.0	0.0	0.0	0.2	154.9
WEC	73.7	49.2	72.8	45.5	128.8	113.1	86.4	107.9	136.4	813.8
NYISO	1,559.8	1,524.8	1,662.1	1,227.8	988.2	1,434.2	1,724.5	1,659.3	1,473.8	13,254.4
HUDS					32.5	36.6	18.4	12.1	7.9	107.6
LIND	15.4	23.6	5.5	0.0	0.0	0.0	0.0	0.0	0.0	44.5
NEPT	278.5	255.2	248.7	253.1	101.5	193.7	420.0	425.6	236.7	2,413.1
NYIS	1,265.9	1,246.0	1,407.8	974.7	854.2	1,203.9	1,286.1	1,221.6	1,229.1	10,689.2
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	9.0	10.0	7.2	1.5	10.4	2.9	2.2	0.0	7.1	50.3
Total without Up-To Congestion	2,439.0	2,200.5	2,470.7	1,937.5	2,100.9	2,462.2	2,694.4	2,778.1	2,563.9	21,647.0
Up-To Congestion	6,342.6	4,817.7	5,101.5	5,150.2	5,081.6	4,592.7	3,823.4	3,796.4	3,688.9	42,395.0
Total	8,781.6	7,018.2	7,572.2	7,087.7	7,182.4	7,054.9	6,517.8	6,574.5	6,252.8	64,042.0

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-10 through Table 9-15 show the Day-Ahead Market interchange totals at the individual interface pricing points. In the first nine months of 2013, up-to congestion transactions accounted for 70.7 percent of all scheduled import MW transactions, 66.2 percent of all scheduled export MW transactions and 48.1 percent of the net interchange volume in the Day-Ahead Market. Net interchange in the Day-Ahead Market, including up-to congestion transactions, is shown by interface pricing point for the first nine months of 2013 in Table 9-10. Up-to congestion transactions by interface pricing point for the first nine months of 2013 are shown in Table 9-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Market are shown in Table 9-12 and Table 9-14, while gross import up-to congestion transactions are show in Table 9-13 and gross export up-to congestion transactions are shown in Table 9-15.

There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast). The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the integration, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO. The NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy market to facilitate the long term day-ahead positions created at the NIPSCO interface prior to the integration.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[29] After

29 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (Accessed October 10, 2013).

the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. The grandfathered agreements for the Southeast interface pricing point have expired. The Southeast interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy market to facilitate the long term day-ahead positions created prior to the consolidation of the Southeast and Southwest interface pricing points.

The MMU recommends that PJM no longer accept long term positions of any kind at the NIPSCO and Southeast interface pricing points and to eliminate these interface pricing points from the Day-Ahead and Real-Time Energy Markets.

In the Day-Ahead Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 57.7 percent of the total net exports: PJM/SouthEXP with 23.3 percent, PJM/NIPSCO with 17.9 percent and PJM/Neptune with 16.6 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 31.0 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interface pricing points had net imports, with three importing interface pricing points accounting for 77.7 percent of the total net imports: PJM/SouthIMP with 36.8 percent, PJM/Southeast with 21.6 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 19.3 percent of the net import volume.[30]

In the Day-Ahead Market, for the first nine months of 2013, up-to congestion transactions had net exports at seven of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points for up-to congestion transactions accounted for 74.2 percent of the total net up-to congestion exports: PJM/SouthEXP with 29.2 percent, PJM/NIPSCO with 23.5 percent and PJM/Southwest with 21.5 percent of the net export up-to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 7.8 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 7.4 percent and PJM/LIND with 0.4 percent). The PJM/NYIS and the PJM/HUDS interface pricing points had net imports in the Day-Ahead Energy Market. Six PJM interface pricing points had net up-to congestion imports, with three importing interface pricing points accounting for 71.6 percent of the total net up-to congestion imports: PJM/MISO with 30.8 percent, PJM/Northwest with 21.9 percent and PJM/Southeast with 18.9 percent of the net import volume.[31]

30 In the Day-Ahead Market, one PJM interface pricing points had a net interchange of zero (PJM/DUKEXP).

Table 9-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					(32.5)	(36.6)	116.2	(49.5)	64.8	62.4
IMO	27.4	235.1	206.5	104.5	100.1	37.8	42.5	27.4	87.8	869.0
LINDENVFT	102.2	14.5	(14.6)	(16.8)	(68.7)	(13.6)	33.3	(95.6)	(48.1)	(107.5)
MISO	192.7	130.5	453.0	228.8	(434.9)	(207.4)	(305.0)	(174.3)	(265.1)	(381.5)
NEPTUNE	(335.1)	(381.7)	(398.9)	(473.6)	(341.6)	(302.0)	(541.9)	(541.5)	(338.8)	(3,655.1)
NIPSCO	(927.2)	(757.5)	(743.5)	(591.9)	(121.5)	(269.9)	(221.9)	(145.1)	(166.9)	(3,945.5)
NORTHWEST	(744.5)	(810.7)	(646.6)	199.5	520.7	128.3	(9.0)	(176.0)	(309.3)	(1,847.5)
NYIS	(662.2)	(576.6)	(506.4)	208.5	10.8	(312.0)	(346.8)	(432.6)	(465.7)	(3,083.0)
OVEC	254.6	210.5	438.4	269.4	92.5	142.3	247.3	69.1	64.0	1,788.1
SOUTHIMP	1,255.6	902.5	877.1	965.4	1,108.3	1,236.1	1,547.2	1,389.6	886.3	10,168.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	202.5	231.5	227.2	0.0	661.2
DUKIMP	22.5	22.0	9.0	7.0	17.5	46.8	63.1	17.0	2.0	207.0
NCMPAIMP	18.3	15.4	14.9	19.1	84.6	53.9	62.1	42.4	16.8	327.4
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	182.9	446.4	340.8	257.3	2,866.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	2,693.8
SOUTHIMP	442.8	307.4	302.0	349.9	423.2	373.5	496.7	394.3	322.8	3,412.6
SOUTHEXP	(1,766.4)	(1,094.4)	(1,527.3)	(1,809.8)	(1,518.9)	(1,370.0)	(1,328.6)	(1,106.6)	(1,073.4)	(12,595.4)
CPLEEXP	(32.4)	(27.8)	(40.7)	(29.6)	(22.8)	(29.5)	(27.4)	(12.7)	(46.8)	(269.5)
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	(1.0)	(0.8)	(0.5)	(0.9)	(1.3)	(1.1)	(1.6)	(0.5)	(0.4)	(8.0)
SOUTHEAST	(49.3)	(28.8)	(26.5)	(123.4)	(213.1)	(118.9)	(190.9)	(59.8)	(50.3)	(861.0)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(1,017.5)	(653.5)	(638.6)	(480.0)	(605.4)	(675.2)	(6,317.8)
SOUTHEXP	(771.5)	(501.6)	(659.5)	(638.4)	(628.2)	(582.0)	(628.8)	(428.3)	(300.8)	(5,139.0)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(916.1)	(685.7)	(967.1)	(766.5)	(1,235.0)	(1,564.5)	(12,727.7)

31 In the Day-Ahead Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

Table 9-11 Up-to Congestion scheduled net interchange volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					0.0	0.0	134.7	(37.4)	72.7	170.0
IMO	(11.9)	189.4	94.5	18.0	(62.6)	(92.8)	(55.8)	(79.2)	(76.9)	(77.3)
LINDENVFT	117.5	28.8	(12.0)	(16.9)	(68.7)	(13.7)	33.3	(95.6)	(48.1)	(75.4)
MISO	500.7	288.8	660.8	422.2	117.7	323.4	164.1	458.2	305.6	3,241.5
NEPTUNE	(56.5)	(126.5)	(150.2)	(220.6)	(240.1)	(108.3)	(121.9)	(115.9)	(102.1)	(1,242.0)
NIPSCO	(927.2)	(757.5)	(743.5)	(591.9)	(121.5)	(269.9)	(221.9)	(145.1)	(166.9)	(3,945.5)
NORTHWEST	(261.6)	(375.0)	(168.9)	622.5	1,004.7	591.2	454.0	296.9	145.6	2,309.5
NYIS	(121.9)	25.3	185.7	415.0	264.0	165.2	183.5	40.1	65.1	1,222.1
OVEC	(306.9)	(281.8)	31.4	(55.2)	(430.3)	(502.5)	(444.6)	(529.4)	(432.1)	(2,951.4)
SOUTHIMP	1,050.5	694.0	668.9	727.3	792.5	786.7	919.7	926.7	749.3	7,315.5
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	181.0	440.7	338.9	256.8	2,856.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	2,693.8
SOUTHIMP	278.5	136.1	117.7	137.9	209.4	229.0	231.7	219.9	205.1	1,765.4
SOUTHEXP	(1,687.4)	(1,022.2)	(1,441.8)	(1,741.8)	(1,447.2)	(1,336.7)	(1,297.4)	(1,093.5)	(1,017.1)	(12,085.1)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(49.3)	(28.8)	(26.5)	(123.4)	(213.1)	(118.9)	(190.9)	(59.8)	(50.3)	(861.0)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(1,017.5)	(653.5)	(638.6)	(480.0)	(605.4)	(675.2)	(6,317.8)
SOUTHEXP	(725.9)	(457.9)	(615.1)	(600.9)	(580.6)	(579.2)	(626.6)	(428.3)	(291.6)	(4,906.3)
Total Interfaces	(1,704.8)	(1,336.7)	(875.0)	(421.3)	(191.6)	(457.4)	(252.3)	(374.2)	(505.0)	(6,118.1)
INTERNAL	22,906.0	23,311.1	27,439.6	32,152.2	34,779.0	34,935.1	29,883.4	29,207.9	26,044.7	260,659.1
Total	21,201.2	21,974.3	26,564.6	31,731.0	34,587.4	34,477.8	29,496.5	28,871.1	25,467.1	254,371.0

Table 9-12 Day-Ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					0.0	0.0	159.7	32.4	116.9	309.0
IMO	268.0	322.5	310.8	285.5	376.4	341.5	316.0	290.3	375.6	2,886.8
LINDENVFT	292.4	210.2	188.5	130.0	145.1	119.8	143.7	37.3	40.2	1,307.1
MISO	719.6	516.2	809.8	770.8	470.0	591.0	429.1	624.6	438.5	5,369.5
NEPTUNE	127.2	32.2	11.5	17.2	10.8	10.1	27.4	6.7	1.7	244.8
NIPSCO	35.0	17.1	15.0	65.2	180.8	135.0	136.6	120.4	60.6	766.0
NORTHWEST	287.9	214.8	229.9	818.0	1,184.5	728.3	561.9	507.2	337.1	4,869.4
NYIS	1,097.0	1,031.5	1,130.2	1,260.6	991.5	1,046.5	1,103.7	966.1	898.1	9,525.2
OVEC	2,096.0	1,643.5	2,137.2	1,858.8	2,029.3	1,879.4	1,325.7	1,364.9	1,533.3	15,868.3
SOUTHIMP	1,255.6	902.5	877.1	965.4	1,108.3	1,236.1	1,547.2	1,389.6	886.3	10,168.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	202.5	231.5	227.2	0.0	661.2
DUKIMP	22.5	22.0	9.0	7.0	17.5	46.8	63.1	17.0	2.0	207.0
NCMPAIMP	18.3	15.4	14.9	19.1	84.6	53.9	62.1	42.4	16.8	327.4
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	182.9	446.4	340.8	257.3	2,866.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	2,693.8
SOUTHIMP	442.8	307.4	302.0	349.9	423.2	373.5	496.7	394.3	322.8	3,412.6
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	6,178.8	4,890.5	5,710.0	6,171.5	6,496.8	6,087.8	5,751.2	5,339.5	4,688.3	51,314.3

Table 9-13 Up-to Congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					0.0	0.0	159.7	32.4	116.9	309.0
IMO	228.7	276.6	198.9	199.1	213.8	210.9	217.7	183.7	211.0	1,940.4
LINDENVFT	292.4	200.9	185.5	129.9	145.1	119.8	143.7	37.3	40.2	1,294.7
MISO	710.9	505.8	772.2	745.5	466.1	590.2	422.5	624.3	430.5	5,267.9
NEPTUNE	127.2	32.2	11.5	17.2	10.8	10.1	27.4	6.7	1.7	244.8
NIPSCO	35.0	17.1	15.0	65.2	180.8	135.0	136.6	120.4	60.6	766.0
NORTHWEST	287.9	214.8	229.9	818.0	1,184.5	728.3	561.9	507.2	337.1	4,869.4
NYIS	370.9	388.3	414.4	492.4	389.9	319.8	347.9	217.3	199.5	3,140.3
OVEC	1,534.5	1,151.2	1,730.2	1,534.2	1,506.5	1,234.6	633.9	766.4	1,037.2	11,128.8
SOUTHIMP	1,050.5	694.0	668.9	727.3	792.5	786.7	919.7	926.7	749.3	7,315.5
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	181.0	440.7	338.9	256.8	2,856.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	2,693.8
SOUTHIMP	278.5	136.1	117.7	137.9	209.4	229.0	231.7	219.9	205.1	1,765.4
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,637.9	3,481.0	4,226.5	4,728.9	4,890.0	4,135.3	3,571.1	3,422.3	3,183.9	36,276.8

Table 9-14 Day-Ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					32.5	36.6	43.4	81.9	52.1	246.6
IMO	240.6	87.4	104.4	181.1	276.4	303.7	273.5	262.9	287.9	2,017.8
LINDENVFT	190.2	195.7	203.1	146.7	213.8	133.4	110.4	132.9	88.3	1,414.6
MISO	526.9	385.6	356.8	541.9	904.9	798.4	734.1	798.8	703.5	5,751.0
NEPTUNE	462.2	413.9	410.4	490.9	352.4	312.1	569.3	548.2	340.5	3,899.9
NIPSCO	962.3	774.6	758.5	657.2	302.4	405.0	358.5	265.5	227.6	4,711.4
NORTHWEST	1,032.4	1,025.5	876.4	618.5	663.8	600.0	570.8	683.1	646.4	6,716.9
NYIS	1,759.2	1,608.1	1,636.5	1,052.1	980.7	1,358.5	1,450.5	1,398.7	1,363.8	12,608.1
OVEC	1,841.4	1,433.0	1,698.8	1,589.5	1,936.8	1,737.2	1,078.5	1,295.8	1,469.3	14,080.2
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,766.4	1,094.4	1,527.3	1,809.8	1,518.9	1,370.0	1,328.6	1,106.6	1,073.4	12,595.4
CPLEEXP	32.4	27.8	40.7	29.6	22.8	29.5	27.4	12.7	46.8	269.5
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	1.0	0.8	0.5	0.9	1.3	1.1	1.6	0.5	0.4	8.0
SOUTHEAST	49.3	28.8	26.5	123.4	213.1	118.9	190.9	59.8	50.3	861.0
SOUTHWEST	912.1	535.5	800.2	1,017.5	653.5	638.6	480.0	605.4	675.2	6,317.8
SOUTHEXP	771.5	501.6	659.5	638.4	628.2	582.0	628.8	428.3	300.8	5,139.0
Total	8,781.6	7,018.2	7,572.2	7,087.7	7,182.4	7,054.9	6,517.8	6,574.5	6,252.8	64,042.0

Table 9-15 Up-to Congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					0.0	0.0	25.0	69.8	44.2	139.0
IMO	240.6	87.3	104.4	181.1	276.4	303.7	273.5	262.9	287.9	2,017.7
LINDENVFT	174.8	172.1	197.6	146.7	213.8	133.4	110.4	132.9	88.3	1,370.1
MISO	210.2	217.0	111.4	323.3	348.4	266.7	258.4	166.1	124.9	2,026.4
NEPTUNE	183.7	158.7	161.7	237.8	250.9	118.4	149.3	122.6	103.8	1,486.8
NIPSCO	962.3	774.6	758.5	657.2	302.4	405.0	358.5	265.5	227.6	4,711.4
NORTHWEST	549.4	589.8	398.7	195.5	179.8	137.1	107.8	210.2	191.6	2,559.9
NYIS	492.8	362.9	228.7	77.4	126.0	154.6	164.4	177.1	134.3	1,918.3
OVEC	1,841.4	1,433.0	1,698.8	1,589.5	1,936.8	1,737.2	1,078.5	1,295.8	1,469.3	14,080.2
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,687.4	1,022.2	1,441.8	1,741.8	1,447.2	1,336.7	1,297.4	1,093.5	1,017.1	12,085.1
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	49.3	28.8	26.5	123.4	213.1	118.9	190.9	59.8	50.3	861.0
SOUTHWEST	912.1	535.5	800.2	1,017.5	653.5	638.6	480.0	605.4	675.2	6,317.8
SOUTHEXP	725.9	457.9	615.1	600.9	580.6	579.2	626.6	428.3	291.6	4,906.3
Total	6,342.6	4,817.7	5,101.5	5,150.2	5,081.6	4,592.7	3,823.4	3,796.4	3,688.9	42,395.0

Table 9-16 Active interfaces: January through September, 2013[32,33,34]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active				
HUDS						Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 9-3 PJM's footprint and its external interfaces

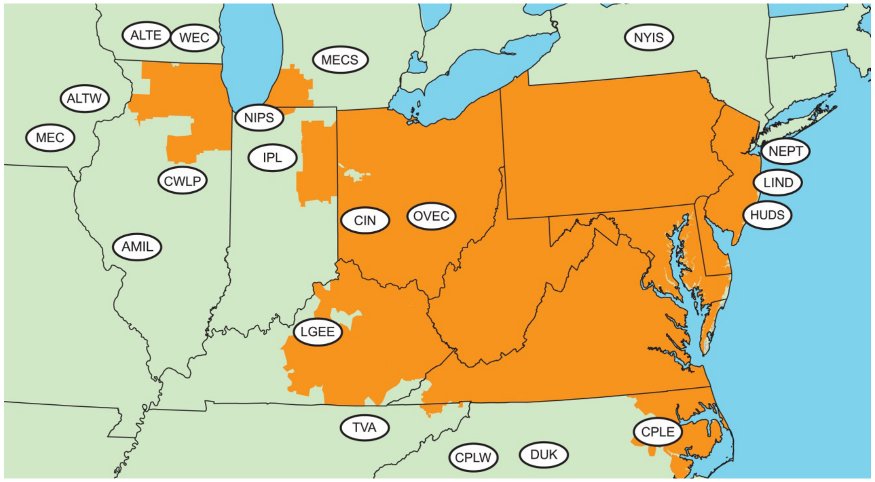


Table 9-17 Active pricing points: January through September, 2013[35]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS						Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active

32 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of June 30, 2013, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.
33 On June 1, 2013, East Kentucky Power Cooperative (EKPC) integrated with PJM, resulting in the elimination of the EKPC Interface.
34 On June 3, 2013, the Hudson DC Line began commercial operation resulting in the addition of the HUDS Interface.

35 On June 3, 2013, the Hudson DC Line began commercial operation resulting in the addition of the HUDSONTP Interface Pricing Point.

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[36]

For the first nine months of 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh. For the first nine months of 2012, net scheduled interchange was 1,051 GWh and net actual interchange was 801 GWh, a difference of 251 GWh.[37] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[38]

Table 9-18 Net scheduled and actual PJM flows by interface (GWh): January through September, 2013

	Actual	Net Scheduled	Difference (GWh)
CPLE	5,666	281	5,385
CPLW	(1,103)	0	(1,103)
DUK	481	1,391	(910)
EKPC	957	(569)	1,526
LGEE	1,361	2,278	(917)
MEC	(1,695)	(3,859)	2,164
MISO	(9,203)	1,804	(11,007)
ALTE	(4,604)	(3,107)	(1,497)
ALTW	(1,731)	(139)	(1,592)
AMIL	8,443	968	7,475
CIN	(3,931)	2,301	(6,231)
CWLP	(289)	0	(289)
IPL	365	431	(66)
MECS	(8,681)	2,557	(11,238)
NIPS	(3,309)	(164)	(3,145)
WEC	4,534	(1,041)	5,575
NYISO	(7,093)	(7,142)	48
HUDS	(82)	(82)	0
LIND	(835)	(835)	0
NEPT	(2,322)	(2,322)	0
NYIS	(3,855)	(3,903)	48
OVEC	9,771	6,756	3,015
TVA	4,331	2,374	1,957
Total	3,474	3,316	158

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the flows that will receive the specific interface price.[39] The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the

36 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

37 The "Net Scheduled" values shown in Table 9-18 include dynamic schedules. Dynamic schedules are commonly used for scheduling generation from one another Balancing Authority Area to another. As defined by NERC, a dynamic schedule is a telemetered reading or value from such a generating unit that is updated in real time and used as a schedule in the AGC/ACE equation of the BA to which it is scheduled. The hourly integrated values of dynamic schedules are treated as a schedule for interchange accounting purposes. Table 9-1 through Table 9-6 represent block scheduled transactions, submitted through the Enhanced Energy Scheduling (EES) application and tagged through the NERC e-tag process only. As a result, the net interchange in Table 9-18 does not match the interchange values shown in Table 9-1 through Table 9-6.

38 See PJM. "M-12: Balancing Operations", Revision 29 (November 1, 2013).

39 The terms balancing authority and control area are used interchangeably in this section. The NERC tag applications maintained the terminology of GCA and LCA after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model," <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf>. (August 2008.)

interfaces. Scheduled transactions are assigned interface pricing points based on the generation balancing authority and load balancing authority. Scheduled power flows are assigned to interfaces based on the OASIS path that reflects the path of energy into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-19 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP Interface Pricing Points were created as part of operating agreements with external balancing authorities, and do not reflect physical ties different from the SouthIMP and SouthEXP interface pricing points.

Because the SouthIMP and SouthEXP Interface Pricing Points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP Interface Pricing Point. Conversely, if there are net actual imports into the PJM footprint from the southern region, there cannot be net actual exports to the southern region and therefore there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points with the southern region, comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points, provides some insight into how effective the interface pricing point mappings are. To accurately calculate the loop flows at the southern region, the net actual flows from the southern region (10,737 GWh of imports at the SouthIMP Interface Pricing Point) are compared with the net scheduled flows at the aggregate southern region (the sum of the net scheduled flows at the SouthIMP and SouthEXP Interface Pricing Points, or 8,769 GWh).

The IMO Interface Pricing Point with the IESO was created to reflect the fact that transactions that originate or sink in the IMO balancing authority create flows that are split between the MISO and NYISO Interface Pricing Points, so a mapping to a single interface pricing point does not reflect the actual flows.

PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Actual flows associated with the IMO Interface Pricing Point are shown as zero because there is no PJM/IMO interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 9-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through September, 2013

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(82)	(82)	0
IMO	0	5,000	(5,000)
LINDENVFT	(835)	(835)	0
MISO	(8,246)	(10,729)	2,483
NEPTUNE	(2,322)	(2,322)	0
NORTHWEST	(1,695)	(25)	(1,670)
NYIS	(3,855)	(3,127)	(728)
OVEC	9,771	6,756	3,015
SOUTHIMP	10,737	10,602	135
CPLEIMP	0	672	(672)
DUKIMP	0	807	(807)
NCMPAIMP	0	427	(427)
SOUTHWEST	0	0	0
SOUTHIMP	10,737	8,695	2,041
SOUTHEXP	0	(1,923)	1,923
CPLEEXP	0	(296)	296
DUKEXP	0	(265)	265
NCMPAEXP	0	(2)	2
SOUTHWEST	0	(41)	41
SOUTHEXP	0	(1,319)	1,319
Total	3,474	3,316	158

Table 9-20 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the Ontario Independent Electricity System Operator (IMO) entered the PJM Energy Market.

Table 9-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through September, 2013

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(82)	(82)	0
LINDENVFT	(835)	(835)	0
MISO	(8,246)	(5,706)	(2,540)
NEPTUNE	(2,322)	(2,322)	0
NORTHWEST	(1,695)	(25)	(1,670)
NYIS	(3,855)	(3,150)	(705)
OVEC	9,771	6,756	3,015
SOUTHIMP	10,737	10,602	135
CPLEIMP	0	672	(672)
DUKIMP	0	807	(807)
NCMPAIMP	0	427	(427)
SOUTHWEST	0	0	0
SOUTHIMP	10,737	8,695	2,041
SOUTHEXP	0	(1,923)	1,923
CPLEEXP	0	(296)	296
DUKEXP	0	(265)	265
NCMPAEXP	0	(2)	2
SOUTHWEST	0	(41)	41
SOUTHEXP	0	(1,319)	1,319
Total	3,474	3,316	158

PJM ensures that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC eTag. Assigning prices in this manner is an adequate method for ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this methodology does not address loop flow issues.

The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, PJM should, recognizing that transactions sourcing in SPP and sinking in PJM will create flows across the southern border, require that market participants submit the transaction to enter the PJM footprint across a neighboring balancing authority that is mapped to the SouthIMP Interface price. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely to the expected actual power flows as possible would result in a more economic dispatch of the entire Eastern Interconnection.

Table 9-21 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the Interface Pricing Points that were assigned to energy transactions that had market paths at each of PJM's interfaces. For example, Table 9-21 shows that for the first nine months of 2013, the majority of imports to the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area of the Ontario Independent Electricity System Operator (IMO), and thus actual flows were assigned the IMO Interface Pricing point (1,569 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM Energy Market at the MISO interface, and thus were assigned the MISO Interface Pricing point (1,368 GWh).

Table 9-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through September, 2013

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(4,604)	(3,107)	(1,497)	IPL		365	431	(66)
	MISO	(4,604)	(3,107)	(1,497)		IMO	0	653	(653)
	NORTHWEST	0	(1)	1		MISO	365	(595)	960
	SOUTHIMP	0	1	(1)		SOUTHEXP	0	(2)	2
ALTW		(1,731)	(139)	(1,592)		SOUTHIMP	0	374	(374)
	MISO	(1,731)	(139)	(1,592)	LGEE		1,361	2,278	(917)
AMIL		8,443	968	7,475		SOUTHEXP	0	(47)	47
	MISO	8,443	730	7,713		SOUTHIMP	1,361	2,326	(964)
	NORTHWEST	0	(1)	1	LIND		(835)	(835)	0
	SOUTHIMP	0	279	(279)		LINDENVFT	(835)	(835)	0
	SOUTHWEST	0	(41)	41	MEC		(1,695)	(3,859)	2,164
CIN		(3,931)	2,301	(6,231)		MISO	0	(4,211)	4,211
	IMO	0	1,569	(1,569)		NORTHWEST	(1,695)	6	(1,701)
	MISO	(3,931)	(1,368)	(2,562)		SOUTHIMP	0	346	(346)
	NORTHWEST	0	(28)	28	MECS		(8,681)	2,557	(11,238)
	NYIS	0	753	(753)		IMO	0	2,800	(2,800)
	SOUTHIMP	0	1,375	(1,375)		MISO	(8,681)	(968)	(7,713)
CPLE		5,666	281	5,385		SOUTHIMP	0	725	(725)
	CPLEEXP	0	(296)	296	NEPT		(2,322)	(2,322)	0
	CPLEIMP	0	672	(672)		NEPTUNE	(2,322)	(2,322)	0
	DUKIMP	0	2	(2)	NIPS		(3,309)	(164)	(3,145)
	SOUTHEXP	0	(14)	14		MISO	(3,309)	(164)	(3,145)
	SOUTHIMP	5,666	(83)	5,749	NYIS		(3,855)	(3,903)	48
CPLW		(1,103)	0	(1,103)		IMO	0	(23)	23
	SOUTHIMP	(1,103)	0	(1,103)		NYIS	(3,855)	(3,880)	25
CWLP		(289)	0	(289)	OVEC		9,771	6,756	3,015
	MISO	(289)	0	(289)		OVEC	9,771	6,756	3,015
DUK		481	1,391	(910)	TVA		4,331	2,374	1,957
	DUKEXP	0	(265)	265		SOUTHEXP	0	(254)	254
	DUKIMP	0	805	(805)		SOUTHIMP	4,331	2,628	1,703
	NCMPAEXP	0	(2)	2	WEC		4,534	(1,041)	5,575
	NCMPAIMP	0	427	(427)		MISO	4,534	(1,041)	5,575
	SOUTHEXP	0	(213)	213	HUDS		(82)	(82)	0
	SOUTHIMP	481	639	(158)		HUDSONTP	(82)	(82)	0
EKPC		957	(569)	1,526	**Grand Total**	**Grand Total**	**3,474**	**3,316**	**158**
	MISO	957	134	822					
	SOUTHEXP	0	(790)	790					
	SOUTHIMP	0	86	(86)					

Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point and interface. This table shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-22 shows that for the first nine months of 2013, the majority of imports to the PJM Energy Market for which a market participant specified a generation control area for which it was assigned the IMO Interface Pricing Point, had market paths that entered the PJM Energy Market at the MECS Interface (2,800 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified a load control area for which it was assigned the IMO Interface Pricing Point, had market paths that exited the PJM Energy Market at the NYIS Interface 23 GWh).

Table 9-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through September, 2013

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(296)	296	NORTHWEST		(1,695)	(25)	(1,670)
	CPLE	0	(296)	296		ALTE	0	(1)	1
CPLEIMP		0	672	(672)		AMIL	0	(1)	1
	CPLE	0	672	(672)		CIN	0	(28)	28
DUKEXP		0	(265)	265		MEC	(1,695)	6	(1,701)
	DUK	0	(265)	265	NYIS		(3,855)	(3,127)	(728)
DUKIMP		0	807	(807)		CIN	0	753	(753)
	CPLE	0	2	(2)		NYIS	(3,855)	(3,880)	25
	DUK	0	805	(805)	OVEC		9,771	6,756	3,015
IMO		0	5,000	(5,000)		OVEC	9,771	6,756	3,015
	CIN	0	1,569	(1,569)	SOUTHEXP		0	(1,319)	1,319
	IPL	0	653	(653)		CPLE	0	(14)	14
	MECS	0	2,800	(2,800)		DUK	0	(213)	213
	NYIS	0	(23)	23		EKPC	0	(790)	790
LINDENVFT		(835)	(835)	0		IPL	0	(2)	2
	LIND	(835)	(835)	0		LGEE	0	(47)	47
MISO		(8,246)	(10,729)	2,483		TVA	0	(254)	254
	ALTE	(4,604)	(3,107)	(1,497)	SOUTHIMP		10,737	8,695	2,041
	ALTW	(1,731)	(139)	(1,592)		ALTE	0	1	(1)
	AMIL	8,443	730	7,713		AMIL	0	279	(279)
	CIN	(3,931)	(1,368)	(2,562)		CIN	0	1,375	(1,375)
	CWLP	(289)	0	(289)		CPLE	5,666	(83)	5,749
	EKPC	957	134	822		CPLW	(1,103)	0	(1,103)
	IPL	365	(595)	960		DUK	481	639	(158)
	MEC	0	(4,211)	4,211		EKPC	0	86	(86)
	MECS	(8,681)	(968)	(7,713)		IPL	0	374	(374)
	NIPS	(3,309)	(164)	(3,145)		LGEE	1,361	2,326	(964)
	WEC	4,534	(1,041)	5,575		MEC	0	346	(346)
NCMPAEXP		0	(2)	2		MECS	0	725	(725)
	DUK	0	(2)	2		TVA	4,331	2,628	1,703
NCMPAIMP		0	427	(427)	SOUTHWEST		0	(41)	41
	DUK	0	427	(427)		AMIL	0	(41)	41
NEPTUNE		(2,322)	(2,322)	0	HUDSONTP		(82)	(82)	0
	NEPT	(2,322)	(2,322)	0		HUDS	(82)	(82)	0
					Grand Total	Grand Total	3,474	3,316	158

PJM and MISO Interface Prices

If interface prices were defined in a comparable manner by PJM and MISO, and if time lags were not built into the rules governing interchange transactions then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that these conditions do not exist is important in explaining the observed relationship between interface prices and inter-RTO power flows, and those price differentials.

Both the PJM/MISO and MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM Interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses within MISO to calculate the PJM/MISO Interface price, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[40,41] Differences in interface price calculations between PJM and MISO limit the ability for price convergence. The use of a common interface price definition including similarly located buses and comparable weights for those buses would help to converge the prices by eliminating artificial limits to that convergence. The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number

40 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 9, 2013). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

41 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010) (Accessed October 10, 2013).

of external buses and selecting buses in close proximity on either side of the border with comparable bus weights.

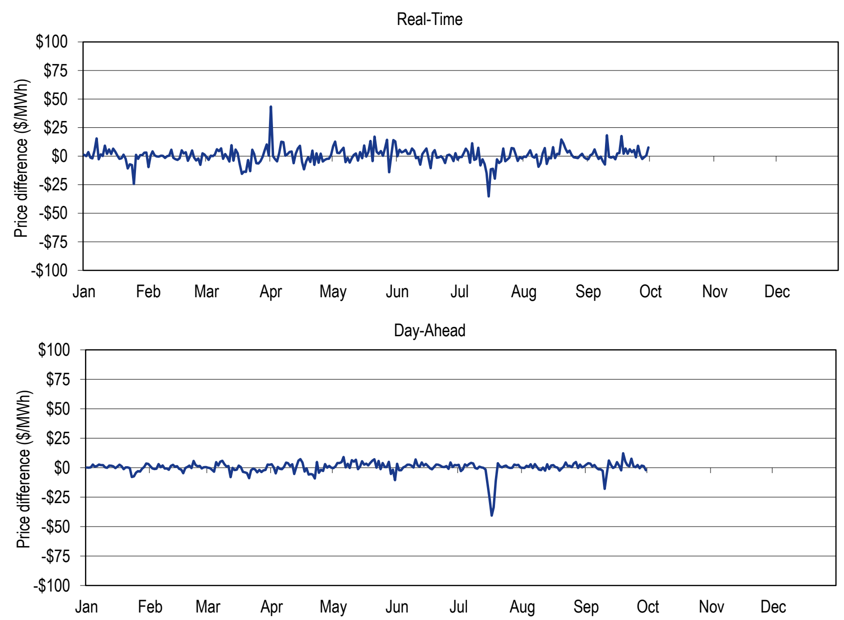
Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first nine months of 2013, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $30.37 while the MISO LMP at the border was $30.84, a difference of $0.48. While the average hourly LMP difference at the PJM/MISO border was only $0.48, the average of the absolute values of the hourly differences was $8.89. The average hourly flow during the first nine months of 2013 was -1,142 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) The direction of flow was consistent with price differentials in only 47.0 percent of hours in the first nine months of 2013. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $11.26. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $7.21. In the first nine months of 2013, when the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from PJM to MISO, the average price difference was $10.86. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from MISO to PJM, the average price difference was $13.67. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from MISO to PJM, the average price difference was $13.42. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from PJM to MISO, the average price difference was $5.72.

In the first nine months of 2013, the day-ahead PJM average hourly LMP at the PJM/MISO border was $31.05 while the MISO LMP at the border was $31.20, a difference of $0.15.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-4). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 9-6).

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through September, 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/MISO Interface

During the first nine months of 2013, the direction of hourly energy flows was consistent with PJM and MISO Interface Price differentials in 3,078 hours (47.0 percent of all hours), and was inconsistent with price differentials in 3,473 hours (53.0 percent of all hours). Table 9-23 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 3,473 hours where flows were uneconomic, 3,000 of those hours (86.4 percent) had a price difference greater than or equal to $1.00 and 1,221 of all uneconomic hours (35.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $272.26. Of the 3,078 hours where flows were economic, 2,682 of those hours (87.1 percent) had a price difference greater than or equal to $1.00 and 1,645 of all economic hours (53.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $887.50.

Table 9-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through September, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	3,473	100.0%	3,078	100.0%
$1.00	3,000	86.4%	2,682	87.1%
$5.00	1,221	35.2%	1,645	53.4%
$10.00	557	16.0%	974	31.6%
$15.00	340	9.8%	651	21.2%
$20.00	220	6.3%	431	14.0%
$25.00	155	4.5%	311	10.1%
$50.00	32	0.9%	99	3.2%
$75.00	12	0.3%	48	1.6%
$100.00	6	0.2%	28	0.9%
$200.00	1	0.0%	5	0.2%
$300.00	0	0.0%	3	0.1%
$400.00	0	0.0%	1	0.0%
$500.00	0	0.0%	1	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[42]

Real-Time and Day-Ahead PJM/NYISO Interface Prices

In the first nine months of 2013, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In the first nine months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In the first nine months of 2013, the PJM average hourly LMP at the PJM/NYISO border was $41.85 while the NYISO LMP at the border was $41.39, a difference of $0.45. While the average hourly LMP difference at the PJM/NYISO border was only $0.45, the average of the absolute value of the hourly difference was $13.69. The average hourly flow during the first nine months of 2013 was -564 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) The direction of flow was consistent with price differentials in 53.1 percent of the hours in the first nine months of 2013. In the first nine months of 2013, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $13.68. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $13.72. In the first nine months of 2013, when the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from PJM to NYISO, the average price difference was $13.44. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from NYISO to PJM, the average price difference was $15.59. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM, the average price difference was $13.65. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and

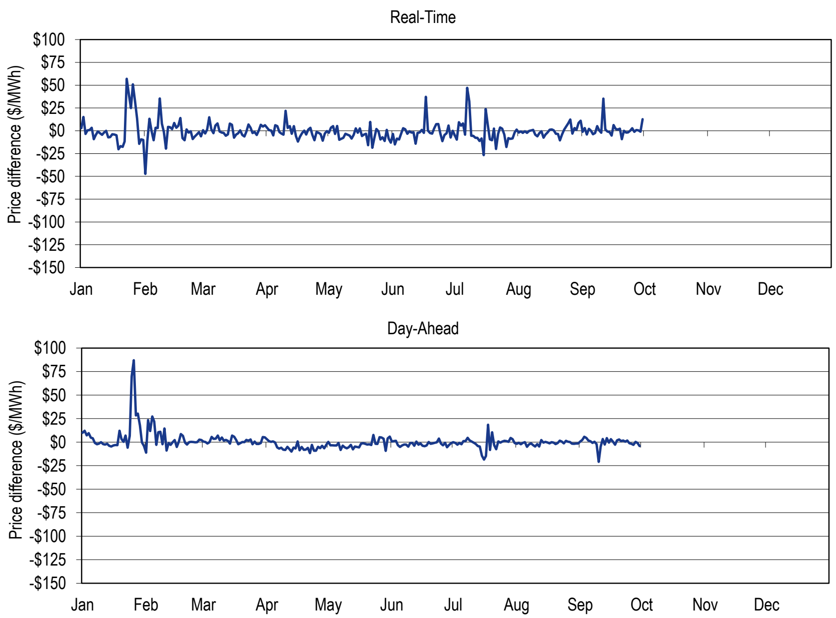
42 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

when power flows were from PJM to NYISO, the average price difference was $13.73.

In the first nine months of 2013, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $42.17 while the NYIS LMP at the border was $42.41, a difference of $0.24.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-5). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 9-6).

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through September, 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/NYISO Interface

During the first nine months of 2013, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,480 (53.1 percent of all hours), and was inconsistent with price differences in 3,071 hours (46.9 percent of all hours). Table 9-24 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 3,071 hours where flows were uneconomic, 2,767 of those hours (90.1 percent) had a price difference greater than or equal to $1.00 and 1,777 of all uneconomic hours (57.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $348.46. Of the 3,480 hours where flows were economic, 3,188 of those hours (91.6 percent) had a price difference greater than or equal to $1.00 and 2,026 of all economic hours (58.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $812.91.

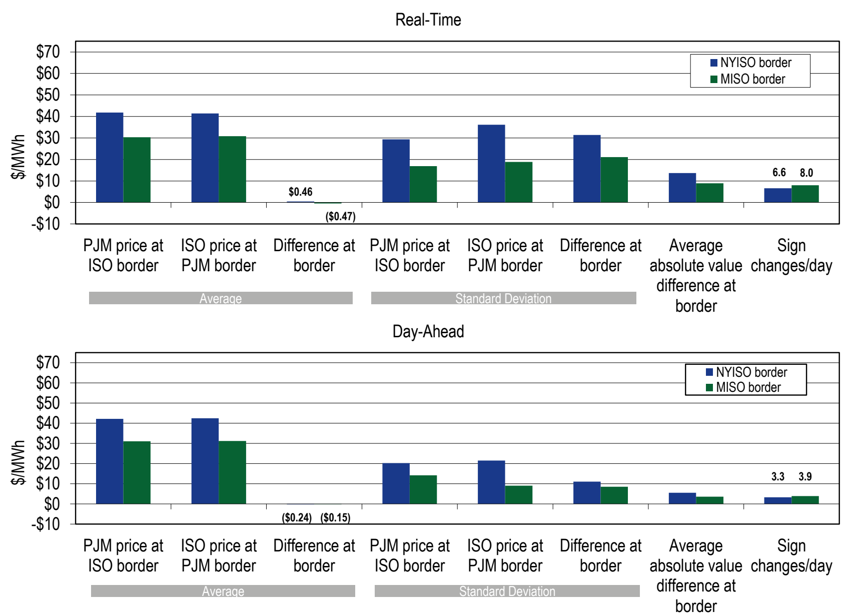
Table 9-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through September, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	3,071	100.0%	3,480	100.0%
$1.00	2,767	90.1%	3,188	91.6%
$5.00	1,777	57.9%	2,026	58.2%
$10.00	1,059	34.5%	1,094	31.4%
$15.00	708	23.1%	708	20.3%
$20.00	507	16.5%	498	14.3%
$25.00	400	13.0%	357	10.3%
$50.00	186	6.1%	162	4.7%
$75.00	94	3.1%	95	2.7%
$100.00	46	1.5%	69	2.0%
$200.00	8	0.3%	15	0.4%
$300.00	2	0.1%	5	0.1%
$400.00	0	0.0%	2	0.1%
$500.00	0	0.0%	2	0.1%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Figure 9-6, including average prices and measures of variability.

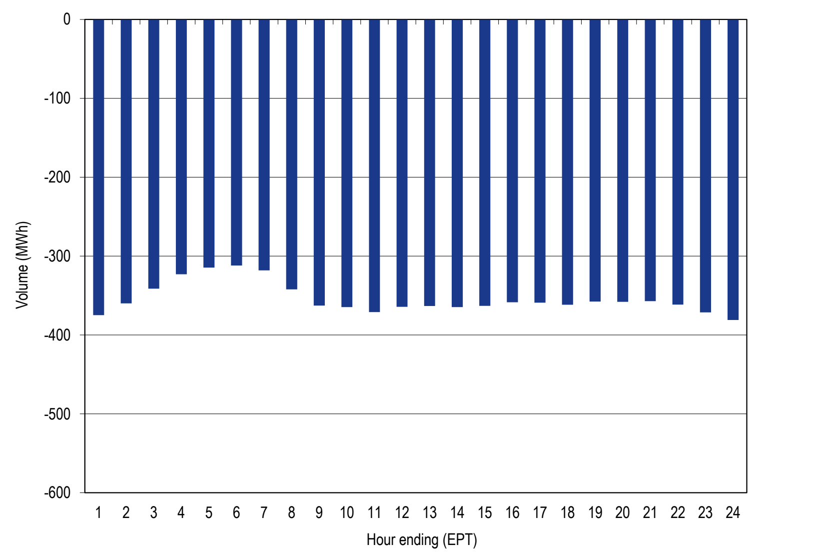
Figure 9-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through September, 2013



Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus. In the first nine months of 2013, the PJM average hourly LMP at the Neptune Interface was $41.72 while the NYISO LMP at the Neptune Bus was $66.36, a difference of $24.64.[43] While the average hourly LMP difference at the PJM/Neptune border was $24.64, the average of the absolute value of the hourly difference was $35.85. The average hourly flow during the first nine months of 2013 was -354 MW.[44] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 69.5 percent of the hours in the first nine months of 2013. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average hourly price difference was $43.01. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $18.91.

Figure 9-7 Neptune hourly average flow: January through September, 2013



43 In the first nine months of 2013, there were 1,128 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $42.62 while the NYISO LMP at the Neptune Bus during non-zero flows was $64.19, a difference of $21.57.

44 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -428 MW.

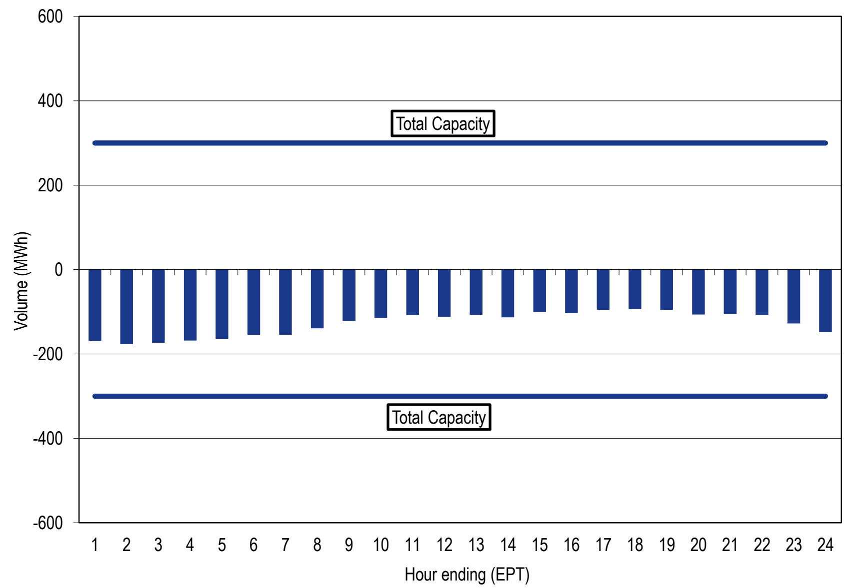
Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus. In the first nine months of 2013, the PJM average hourly LMP at the Linden Interface was $41.18 while the NYISO LMP at the Linden Bus was $49.71, a difference of $8.53.[45] While the average hourly LMP difference at the PJM/Linden border was $8.53, the average of the absolute value of the hourly difference was $18.86. The average hourly flow during the first nine months of 2013 was -127 MW.[46] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 65.8 percent of the hours in the first nine months of 2013. When the NYISO/Linden Interface price was greater than the PJM/LIND Interface price, the average hourly price difference was $21.18. When the PJM/LIND Interface price was greater than the NYISO/Linden Interface price, the average price difference was $14.61.

45 In the first nine months of 2013, there were 1,351 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $41.23 while the NYISO LMP at the Neptune Bus during non-zero flows was $48.95, a difference of $7.72.

46 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Linden VFT line was -161 MW.

Figure 9-8 Linden hourly average flow: January through September, 2013[47]



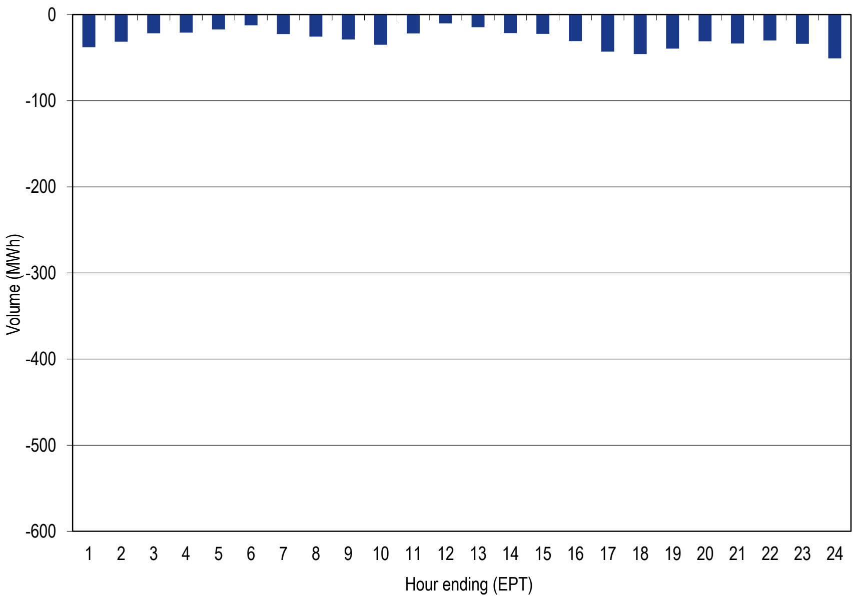
Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) line began commercial operation on June 3, 2013. The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights). In the first four months of operations, the direction of the average

47 The Linden VFT line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie line.

hourly flow was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus. The PJM average hourly LMP at the Hudson Interface was $41.47 while the NYISO LMP at the Hudson Bus was $44.11, a difference of $2.64.[48] While the average hourly LMP difference at the PJM/Hudson border was $2.64, the average of the absolute value of the hourly difference was $8.09. The average hourly flow during the first four months of operations was -22 MW.[49] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 60.9 percent of the hours in the first four months of operations. When the NYISO/Hudson Interface price was greater than the PJM/HUDS Interface price, the average hourly price difference was $20.80. When the PJM/HUDS Interface price was greater than the NYISO/Hudson Interface price, the average price difference was $16.11.

Figure 9-9 Hudson hourly average flow: June through September, 2013



48 In the first four months of operations, there were 2,987 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $48.65 while the NYISO LMP at the Hudson Bus during non-zero flows was $55.00, a difference of $6.35.

49 The average hourly flow during the first four months of operations, ignoring hours with no flow, on the Hudson line was -120 MW.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with the NYISO, an implemented operating agreement with MISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., and a reliability coordination agreement with VACAR South.

PJM and MISO Joint Operating Agreement[50]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[51]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses nine buses within MISO to calculate the PJM/MISO Interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.[52]

Coordinated Flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A Reciprocal Coordinated Flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on

50 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed October 10, 2013).

51 See www.pjm.com "2012 PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-joint-common.aspx>.

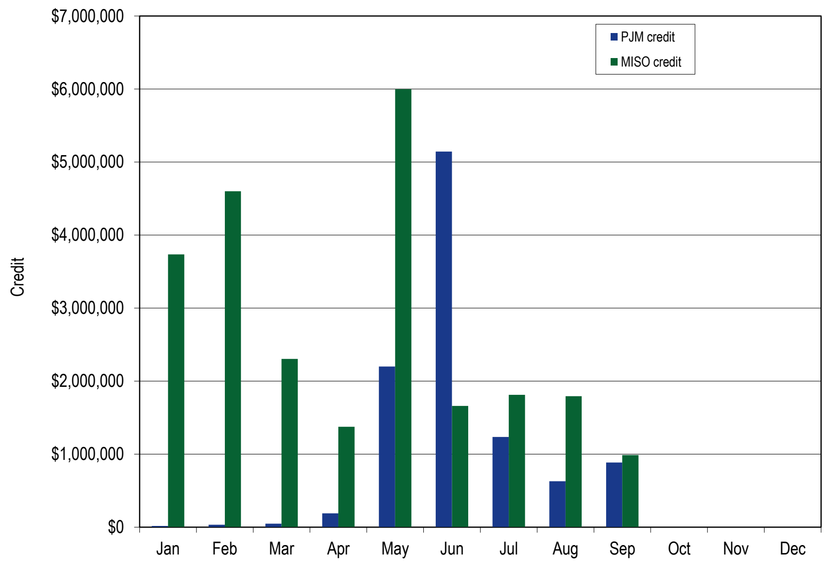
52 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of August 6, 2013, PJM had 166 flowgates eligible for M2M coordination. Between August 6, 2013 and September 30, 2013, PJM added five and deleted 21 flowgates, leaving 150 flowgates eligible for M2M coordination as of October 1, 2013. As of August 6, 2013, MISO had 269 flowgates eligible for M2M coordination. Between August 6, 2013 and September 30, 2013, MISO added 51 and deleted 33 flowgates, leaving 287 flowgates eligible for M2M coordination as of October 1, 2013.

During the first nine months of 2013, the market to market operations resulted in MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-10 Credits for coordinated congestion management: January through September, 2013[53]



53 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)[54]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses two buses within NYISO to calculate the PJM/MISO Interface pricing point LMP while The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) using the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

Coordinated Flowgates (CF) are flowgates that are monitored or controlled by either PJM or NYISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A Reciprocal Coordinated Flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCF's are subject to the market to market congestion management process.

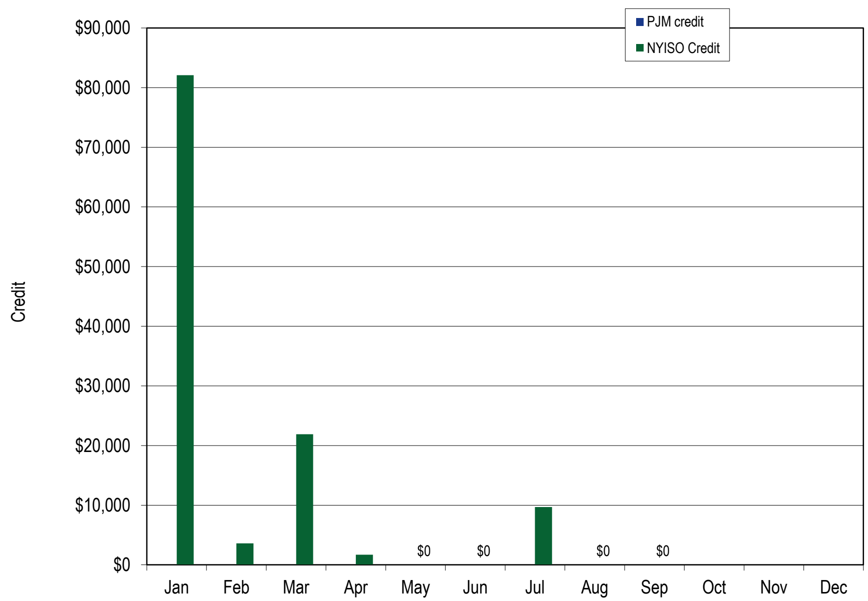
In the first nine months of 2013, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the

54 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (April 15, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed October 10, 2013).

approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

During the first nine months of 2013, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-11 Credits for coordinated congestion management (flowgates): January through September, 2013[55]

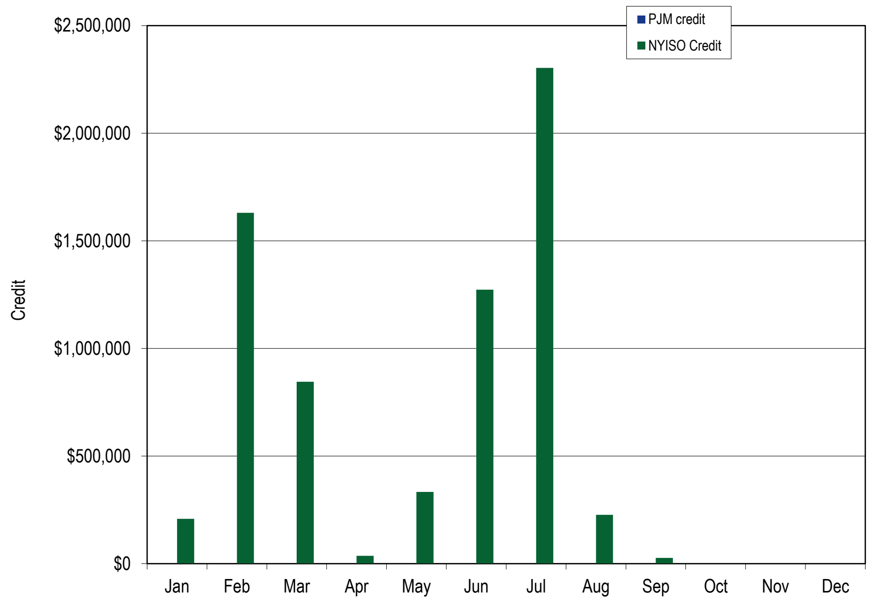


The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the NYISO – PJM interface. This real-time coordination results in a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real-time to manage constraints.[56] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In the first nine months of 2013, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 9-12 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

55 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

56 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (April 15, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed October 10, 2013).

Figure 9-12 Credits for coordinated congestion management (Ramapo PARs): January through September, 2013[57]



PJM, MISO and TVA Joint Reliability Coordination Agreement (JRCA)

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of MISO and PJM and the service territory of TVA. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers. The parties meet on a yearly basis, and, in the first nine months of 2013, there were no developments. The agreement continued to be in effect in the first nine months of 2013.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[58] On January 20, 2011, the Commission conditionally accepted the compliance filing.

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems. The parties meet on a yearly basis, and, in the first nine months of 2013, there were no developments. The agreement remained in effect in the first nine months of 2013.

57 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

58 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[59]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[60] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[61] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. However, the MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

Table 9-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$33.38	$34.07	$33.59	$33.59	($0.21)	$0.48
PEC	$33.79	$34.87	$33.59	$33.59	$0.21	$1.28
NCMPA	$33.73	$33.84	$33.59	$33.59	$0.14	$0.25

59 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (Accessed October 10, 2013).

60 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

61 See Docket Nos. ER12-1338-000 and ER12-1343-000.

Table 9-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$34.61	$35.15	$34.34	$34.27	$0.27	$0.88
PEC	$34.99	$35.61	$34.34	$34.27	$0.64	$1.34
NCMPA	$34.88	$34.97	$34.34	$34.27	$0.53	$0.70

Other Agreements/Protocols with Bordering Areas

Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey including lines controlled by PJM.[62] This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001.[63]

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[64] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special protocol indefinitely.[65] The settlement defined ConEd's cost responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. ConEd is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent roll over of the service.[66] ConEd's rolled over service became effective on May 1, 2012. The additional transmission charges have been included in the wheeling agreement data as shown in Table 9-27 below reflecting those charges effective May 1, 2012.

62 See "Section 4 – Operating Reserve" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.

63 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

64 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

65 132 FERC ¶ 61,221 (2010).

66 The terms of the settlement state that ConEd shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.

Table 9-27 Con Edison and PSE&G wheeling agreement data: January through September, 2013

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$6,666,452	$15,964	$6,682,416	$0	$0	$0
Congestion Credit			$2,806,474			$0
Adjustments and Transmission Charges			($27,175,184)			$1,920
Net Charge			$31,051,125			($1,920)

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM issued 45 TLRs of level 3a or high in the first nine months of 2013, compared to 29 TLRs issued in the first nine months of 2012. The number of different flowgates for which PJM declared TLRs increased from nine in the first nine months of 2012 to 23 in the first nine months of 2013. The total MWh of transaction curtailments increased by 6.8 percent, from 125,339 MWh in the first nine months of 2012 to 133,869 MWh in the first nine months of 2013.

MISO called more TLRs of level 3a or higher in the first nine months of 2013 than in the first nine months of 2012. MISO TLRs increased from 118 in the first nine months of 2012 to 285 in the first nine months of 2013.

NYISO called fewer TLRs of level 3a or higher in the first nine months of 2013 than in the first nine months of 2012. NYISO TLRs decreased from 55 in the first nine months of 2012 to 3 in the first nine months of 2013.

Table 9-28 PJM MISO, and NYISO TLR procedures: January, 2010 through September, 2013[67]

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-10	6	23	20	3	5	4	18,393	13,387	60,427
Feb-10	1	9	19	1	7	3	1,249	13,095	69,569
Mar-10	6	18	21	3	10	6	2,376	27,412	78,366
Apr-10	15	40	14	7	11	2	26,992	29,832	59,041
May-10	11	20	7	4	12	4	22,193	54,702	10,463
Jun-10	19	19	13	6	8	6	64,479	183,228	23,969
Jul-10	15	25	4	8	8	3	44,210	169,667	2,262
Aug-10	12	22	0	9	7	0	32,604	189,756	0
Sep-10	11	15	1	7	7	1	82,066	32,782	232
Oct-10	4	26	1	3	12	1	2,305	29,574	0
Nov-10	1	25	0	1	10	0	59	66,113	0
Dec-10	9	7	4	6	5	1	18,509	5,972	4,224
Jan-11	7	8	29	5	5	4	75,057	14,071	156,508
Feb-11	6	7	10	5	4	2	6,428	23,796	27,649
Mar-11	0	14	28	0	5	3	0	10,133	57,472
Apr-11	3	23	12	3	9	3	8,129	44,855	15,761
May-11	9	15	15	4	7	4	18,377	36,777	24,857
Jun-11	15	14	24	7	6	9	17,865	19,437	31,868
Jul-11	7	8	17	4	7	7	18,467	3,697	20,645
Aug-11	4	6	4	4	4	2	3,624	11,323	12,579
Sep-11	7	17	7	6	7	3	6,462	25,914	11,445
Oct-11	4	16	5	2	6	1	16,812	27,392	3,665
Nov-11	0	10	2	0	5	2	0	22,672	484
Dec-11	0	5	8	0	3	2	0	8,659	26,523
Jan-12	1	9	5	1	6	2	4,920	6,274	8,058
Feb-12	4	6	16	2	6	2	0	5,177	35,451
Mar-12	1	11	10	1	6	2	398	31,891	26,761
Apr-12	0	14	11	0	7	1	0	8,408	29,911
May-12	2	17	12	1	10	5	3,539	30,759	21,445
Jun-12	0	24	0	0	7	0	0	31,502	0
Jul-12	11	19	1	5	4	1	34,197	46,512	292
Aug-12	8	13	0	1	6	0	61,151	13,403	0
Sep-12	2	5	0	1	4	0	21,134	12,494	0
Oct-12	3	9	0	2	6	0	0	12,317	0
Nov-12	4	10	5	2	6	2	444	24,351	6,250
Dec-12	1	22	0	1	12	0	0	17,761	0
Jan-13	4	42	2	3	17	1	13,453	103,463	1,045
Feb-13	4	26	0	3	10	0	14,609	66,086	0
Mar-13	0	39	0	0	13	0	0	53,122	0
Apr-13	1	45	0	1	20	0	84	64,938	0
May-13	10	29	0	7	14	0	879	20,778	0
Jun-13	4	25	1	1	11	1	5,036	76,240	4,102
Jul-13	12	28	0	2	9	0	88,623	80,328	0
Aug-13	4	19	0	4	8	0	3,469	38,608	0
Sep-13	6	33	0	5	14	0	7,716	90,188	0

67 The curtailment volume for PJM TLRs was taken from the individual NERC TLR history reports as posted in the Interchange Distribution Calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLRs was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx> (Accessed October 10, 2013).

Table 9-29 Number of TLRs by TLR level by reliability coordinator: January through September, 2013

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2013	ICTE	0	0	0	0	0	0	0
	MISO	91	32	1	107	54	0	285
	NYIS	3	0	0	0	0	0	3
	ONT	7	0	0	0	0	0	7
	PJM	24	19	0	1	1	0	45
	SOCO	0	0	0	0	0	0	0
	SWPP	241	83	0	54	12	0	390
	TVA	26	25	1	5	5	0	62
	VACS	3	3	0	0	0	0	6
Total		395	162	2	167	72	0	798

On February 9, 2013, PJM issued a TLR level 5a. A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point-to-point transmission service, to flow.[68] The TLR 5a, issued on February 9, 2013, was required to address system operating limits on the Bridgewater to Middlesex 230 kV line for the loss of the Smithburg to East Windsor 230 kV line in northern New Jersey, and resulted in the curtailment of 223 MWh of transactions utilizing Firm transmission.

On September 11, 2013, PJM issued a TLR level 5b. A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL. The TLR 5b, issued on September 11, 2013, was required to address system operating limits on the Bridgewater to Middlesex 230 kV line for the loss of Red Oak A and B units in northern New Jersey, and resulted in the curtailment of 1,480 MWh of transactions utilizing firm transmission.

Between January 1, 2003, and February 9, 2013, PJM had only issued 20 TLR's of level 5a or 5b, and none since 2008.

Up-To Congestion

The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the Real-Time Energy Market.[69]

Following elimination of the requirement to procure transmission for up-to congestion transactions, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 105,472 bids per day, with an average cleared volume of 1,221,114 MWh per day, in the first nine months of 2013, compared to an average of 58,273 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012 (See Figure 9-13).

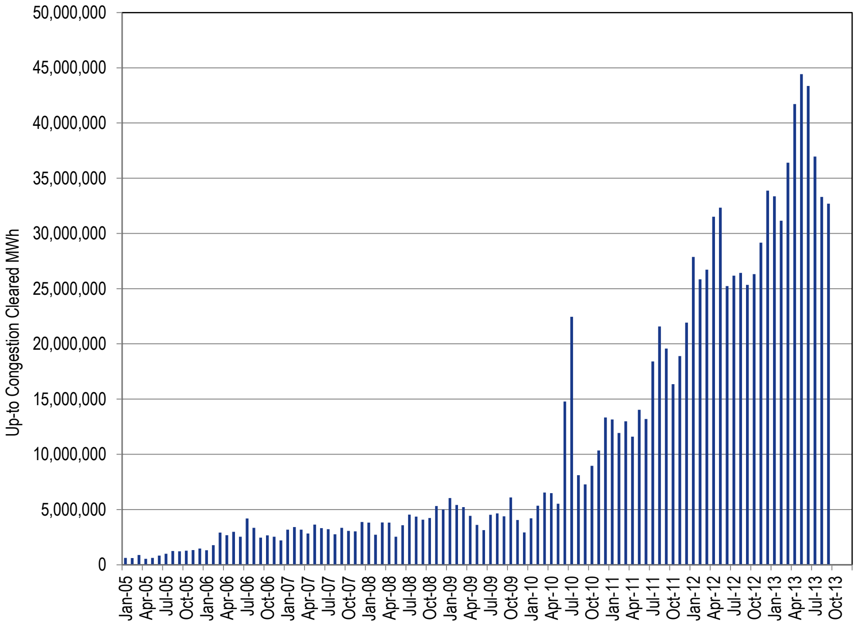
Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Despite that, up-to congestion transactions do not pay operating reserves charges. Up-to congestion transactions also significantly affect FTR funding. The FTR forfeiture rule does not currently apply to UTCs.

68 See the *2012 State of the Market Report for PJM*, Volume II, "Appendix E - Interchange Transactions," for a discussion on all TLR levels and the historical volumes of TLR's initiated by PJM and all other reliability coordinators in the Eastern Interconnection.

69 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges. The level of the fee should be determined based on the method defined in the State of the Market Report.[70]

Figure 9-13 Monthly up-to congestion cleared bids in MWh: January, 2005 through September, 2013



70 See the *2013 Quarterly State of the Market Report for PJM: January to September*, Section 4, "Operating Reserves."

Table 9-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through September, 2013

	Bid MW					Bid Volume					Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-09	4,218,910	5,787,961	319,122	-	10,325,993	90,277	74,826	6,042	-	171,145	2,591,211	3,242,491	202,854	-	6,036,556	56,132	45,303	4,210	-	105,645
Feb-09	3,580,115	4,904,467	318,440	-	8,803,022	64,338	70,874	6,347	-	141,559	2,374,734	2,836,344	203,907	-	5,414,985	42,101	44,423	4,402	-	90,926
Mar-09	3,649,978	5,164,186	258,701	-	9,072,865	64,714	72,495	5,531	-	142,740	2,285,412	2,762,459	178,507	-	5,226,378	42,408	42,007	4,299	-	88,714
Apr-09	2,607,303	5,085,912	73,931	-	7,767,146	47,970	67,417	2,146	-	117,533	1,797,302	2,582,294	48,478	-	4,428,074	32,088	35,987	1,581	-	69,656
May-09	2,196,341	4,063,887	106,860	-	6,367,088	40,217	54,745	1,304	-	96,266	1,496,396	2,040,737	77,553	-	3,614,686	26,274	29,720	952	-	56,946
Jun-09	2,598,234	3,132,478	164,903	-	5,895,615	47,625	44,755	2,873	-	95,253	1,540,169	1,500,560	88,723	-	3,129,452	28,565	23,307	1,522	-	53,394
Jul-09	3,984,680	3,776,957	296,910	-	8,058,547	67,039	56,770	5,183	-	128,992	2,465,891	1,902,807	163,129	-	4,531,826	41,924	31,176	2,846	-	75,946
Aug-09	3,551,396	4,388,435	260,184	-	8,200,015	64,652	64,052	3,496	-	132,200	2,278,431	2,172,133	194,415	-	4,644,978	41,774	34,576	2,421	-	78,771
Sep-09	2,948,353	4,179,427	156,270	-	7,284,050	51,006	64,103	2,405	-	117,514	1,774,589	2,479,898	128,344	-	4,382,831	31,962	40,698	1,944	-	74,604
Oct-09	3,172,034	6,371,230	154,825	-	9,698,089	46,989	100,350	2,217	-	149,556	2,060,371	3,931,346	110,646	-	6,102,363	31,634	70,964	1,672	-	104,270
Nov-09	3,447,356	3,851,334	103,325	-	7,402,015	53,067	61,906	1,236	-	116,209	2,065,813	1,932,595	51,929	-	4,050,337	33,769	32,916	653	-	67,338
Dec-09	2,323,383	2,502,529	66,497	-	4,892,409	47,099	47,223	1,430	-	95,752	1,532,579	1,359,936	34,419	-	2,926,933	31,673	28,478	793	-	60,944
Jan-10	3,794,946	3,097,524	212,010	-	7,104,480	81,604	55,921	3,371	-	140,896	2,250,689	1,789,018	161,977	-	4,201,684	49,064	33,640	2,318	-	85,022
Feb-10	3,841,573	3,937,880	316,150	-	8,095,603	80,876	80,685	2,269	-	163,830	2,627,101	2,435,650	287,162	-	5,349,913	50,958	48,008	1,812	-	100,778
Mar-10	4,877,732	4,454,865	277,180	-	9,609,777	97,149	74,568	2,239	-	173,956	3,209,064	3,071,712	263,516	-	6,544,292	60,277	48,596	2,064	-	110,937
Apr-10	3,877,306	5,558,718	210,545	-	9,646,569	67,632	85,358	1,573	-	154,563	2,622,113	3,690,889	170,020	-	6,483,022	42,635	54,510	1,154	-	98,299
May-10	3,800,870	5,062,272	149,589	-	9,012,731	74,996	78,426	1,620	-	155,042	2,366,149	3,049,405	112,700	-	5,528,253	47,505	48,996	1,112	-	97,613
Jun-10	9,126,963	9,568,549	1,159,407	-	19,854,919	95,155	89,222	6,960	-	191,337	6,863,803	6,850,098	1,072,759	-	14,786,660	59,733	55,574	5,831	-	121,138
Jul-10	12,818,141	11,526,089	5,420,410	-	29,764,640	124,929	106,145	18,948	-	250,022	8,971,914	8,237,557	5,241,264	-	22,450,734	73,232	60,822	16,526	-	150,580
Aug-10	8,231,393	6,767,617	888,591	-	15,887,601	115,043	87,876	10,664	-	213,583	4,430,832	2,894,314	785,726	-	8,110,871	62,526	40,485	8,884	-	111,895
Sep-10	7,768,878	7,561,624	349,147	-	15,679,649	184,697	161,929	4,653	-	351,279	3,915,814	3,110,580	256,039	-	7,282,433	63,405	45,264	3,393	-	112,062
Oct-10	8,732,546	9,795,666	476,665	-	19,004,877	189,748	154,741	7,384	-	351,873	4,150,104	4,564,039	246,594	-	8,960,736	76,042	65,223	3,670	-	144,935
Nov-10	11,636,949	9,272,885	537,369	-	21,447,203	253,594	170,470	9,366	-	433,430	5,765,905	4,312,645	275,111	-	10,353,661	112,250	71,378	4,045	-	187,673
Dec-10	17,769,014	12,863,875	923,160	-	31,556,049	307,716	215,897	15,074	-	538,687	7,851,235	5,150,286	337,157	-	13,338,678	136,582	93,299	7,380	-	237,261
Jan-11	20,275,932	11,807,379	921,120	-	33,004,431	351,193	210,703	17,632	-	579,528	7,917,986	4,925,310	315,936	-	13,159,232	151,753	91,557	8,417	-	251,727
Feb-11	18,418,511	13,071,483	800,630	-	32,290,624	345,227	226,292	17,634	-	589,153	6,806,039	4,879,207	248,573	-	11,933,818	151,003	99,302	8,851	-	259,156
Mar-11	17,330,353	12,919,960	749,276	-	30,999,589	408,628	274,709	15,714	-	699,051	7,104,642	5,603,583	275,682	-	12,983,906	178,620	124,990	7,760	-	311,370
Apr-11	17,215,352	9,321,117	954,283	-	27,490,752	513,881	265,334	17,459	-	796,674	7,452,366	3,797,819	351,984	-	11,602,168	229,707	113,610	8,118	-	351,435
May-11	21,058,071	11,204,038	2,937,898	-	35,200,007	562,819	304,589	24,834	-	892,242	8,294,422	4,701,077	1,031,519	-	14,027,018	261,355	143,956	11,116	-	416,427
Jun-11	20,455,508	12,125,806	395,833	-	32,977,147	524,072	285,031	12,273	-	821,376	7,632,235	5,361,825	198,482	-	13,192,543	226,747	132,744	6,363	-	365,854
Jul-11	24,273,892	16,837,875	409,863	-	41,521,630	603,519	338,810	13,781	-	956,110	9,585,027	8,617,284	205,599	-	18,407,910	283,287	186,866	7,008	-	477,161
Aug-11	23,790,091	21,014,941	229,895	-	45,034,927	591,170	403,269	8,278	-	1,002,717	10,594,771	10,875,384	103,141	-	21,573,297	274,398	208,593	3,648	-	486,639
Sep-11	21,740,208	18,135,378	232,626	-	40,108,212	526,945	377,158	7,886	-	911,989	10,219,806	9,270,121	82,200	-	19,572,127	270,088	185,585	3,444	-	459,117
Oct-11	20,240,161	19,476,556	333,077	-	40,049,794	540,877	451,507	8,609	-	1,000,993	8,376,208	7,853,947	126,718	-	16,356,873	255,206	198,778	4,236	-	458,220
Nov-11	27,007,141	28,994,789	507,788	-	56,509,718	594,397	603,029	13,379	-	1,210,805	9,064,570	9,692,312	131,670	-	18,888,552	254,851	256,270	5,686	-	516,807
Dec-11	34,990,790	34,648,433	531,616	-	70,170,839	697,524	655,222	14,187	-	1,366,933	11,738,910	10,049,685	137,689	-	21,926,284	281,304	248,008	6,309	-	535,621
Jan-12	38,906,228	36,928,145	620,448	-	76,454,821	745,424	689,174	16,053	-	1,450,651	13,610,725	14,120,791	145,773	-	27,877,288	289,524	304,072	5,078	-	598,674
Feb-12	37,231,115	36,736,507	323,958	-	74,291,580	739,200	724,477	8,572	-	1,472,249	12,883,355	12,905,553	54,724	-	25,843,632	299,055	276,563	2,175	-	577,793
Mar-12	38,824,528	39,163,001	297,895	-	78,285,424	802,983	842,857	8,971	-	1,654,811	13,328,968	13,306,689	89,262	-	26,724,918	320,210	320,252	3,031	-	643,493
Apr-12	42,085,326	44,565,341	436,632	-	87,087,299	884,004	917,430	12,354	-	1,813,788	15,050,798	16,297,303	171,252	-	31,519,354	369,273	355,669	4,655	-	729,597
May-12	44,436,245	43,888,405	489,938	-	88,814,588	994,735	885,319	10,294	-	1,890,348	17,416,386	14,733,838	189,667	-	32,339,891	434,919	343,872	4,114	-	782,905
Jun-12	38,962,548	32,828,393	975,776	-	72,766,718	872,764	684,382	21,781	-	1,578,927	12,675,852	12,311,609	250,024	-	25,237,485	355,731	295,911	6,891	-	658,533
Jul-12	45,565,682	41,589,191	855,676	-	88,010,549	1,077,721	911,300	27,173	-	2,016,194	13,001,225	12,823,361	348,946	-	26,173,532	399,135	321,062	9,958	-	730,155
Aug-12	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
Oct-12	35,567,607	42,489,970	1,415,992	-	79,473,570	908,200	1,048,029	46,802	-	2,003,031	11,969,576	13,949,871	392,286	-	26,311,733	345,788	376,513	14,089	-	736,390
Nov-12	24,795,325	25,498,103	1,258,755	52,022,007	103,574,190	542,992	614,349	43,829	1,631,255	2,832,425	6,517,798	7,872,496	286,535	14,482,701	29,159,529	186,492	245,943	15,042	509,436	956,913
Dec-12	22,597,985	22,560,837	1,727,510	84,548,868	131,435,199	489,208	515,873	55,376	2,767,292	3,827,749	5,116,607	6,350,080	454,289	21,958,089	33,879,065	180,592	224,830	24,459	820,991	1,250,872
Jan-13	16,718,393	21,312,321	2,010,317	76,937,535	116,978,566	422,501	527,037	63,227	2,115,649	3,128,414	4,115,418	5,820,177	522,459	22,906,008	33,364,063	149,282	199,123	23,926	657,602	1,029,933
Feb-13	12,567,004	15,509,978	1,477,275	67,258,116	96,812,373	352,963	400,563	43,133	1,798,434	2,595,093	3,019,380	4,356,113	461,615	23,311,066	31,148,173	110,397	158,085	15,892	669,364	953,738
Mar-13	14,510,721	17,019,755	1,601,487	88,109,152	121,241,114	372,402	402,711	48,112	1,959,294	2,782,519	3,868,303	4,743,283	358,180	27,439,606	36,409,373	131,506	166,295	17,884	774,020	1,089,705
Apr-13	14,538,907	17,419,505	1,337,680	105,927,107	139,223,200	358,245	364,008	47,048	2,275,846	3,045,147	4,413,047	4,834,302	315,867	32,152,243	41,715,459	145,860	157,031	16,315	892,562	1,211,768
May-13	16,565,868	17,640,682	1,640,097	115,572,648	151,419,296	431,892	389,254	54,873	2,660,793	3,536,812	4,556,277	4,747,887	333,677	34,778,962	44,416,803	144,444	144,482	16,317	944,116	1,249,359
Jun-13	16,698,203	18,904,971	1,337,373	128,595,957	165,536,504	452,145	433,010	48,007	3,384,811	4,317,973	3,823,166	4,280,538	312,158	34,935,141	43,351,002	143,223	151,603	17,518	1,116,318	1,428,662
Jul-13	15,436,914	16,428,662	1,473,144	116,673,912	150,012,631	430,120	387,969	49,712	3,075,624	3,943,425	3,250,706	3,502,990	320,374	29,883,430	36,957,500	131,535	127,032	17,948	957,260	1,233,775
Aug-13	12,332,984	14,354,140	1,370,624	89,306,595	117,364,344	328,835	326,637	40,325	2,223,269	2,919,066	2,862,764	3,232,565	309,069	26,900,995	33,305,393	111,715	122,061	16,299	848,490	1,098,565
Sep-13	10,767,257	11,322,974	729,332	75,686,010	98,505,573	264,095	262,486	21,968	1,976,741	2,525,290	2,962,619	3,467,611	221,329	26,044,742	32,696,300	102,984	107,604	10,233	792,766	1,013,587
TOTAL	986,228,391	953,011,602	45,472,967	1,000,637,907	2,985,350,867	22,180,464	19,800,506	1,024,433	25,869,008	68,874,411	363,374,731	353,501,206	20,031,738	294,792,983	1,031,700,657	9,163,568	8,186,546	430,622	8,982,925	26,763,661

In the first nine months of 2013, the cleared MW volume of up-to congestion transactions was comprised of 9.9 percent imports, 11.7 percent exports, 0.9 percent wheeling transactions and 77.5 percent internal transactions. Only 0.1 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load which can create loop flows and inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM Energy Market, at the PJM/NYIS Interface regardless of the submitted market path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT market path, and a second segment on the ONT-MISO-PJM market path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source is Ontario (the ONT Interface price).

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create business rules that prevent sham scheduling among and between the RTO/ISO markets.

Elimination of Ontario Interface Pricing Point

An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy.

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[71] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area and Load Control Area as specified on the NERC Tag. Transactions between PJM and external balancing authorities need to be priced at the PJM border.

The IMO Interface Pricing Point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO Interface Pricing Points. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

The IMO Interface Pricing Point is defined as the LMP at the Bruce bus, which is located in IESO. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing. Because 5,022 GWh of the 5,045 GWh of net transactions between PJM and IESO wheeled through MISO during the first nine months of 2013, (see Table 9-22), the MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink

71 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 9, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

in the IESO balancing authority until the stakeholder process determines an alternative approach to pricing these transactions.

PJM and NYISO Coordinated Interchange Transaction Proposal

The Coordinated Transaction Scheduling (CTS) proposal provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated. The evaluation will be based on the forward-looking prices as determined by PJM's Intermediate Term Security Constrained Economic Dispatch tool (ITSCED) and the NYISO's Real Time Commitment (RTC) tool. PJM shares its PJM/NYISO interface price from the ITSCED results with the NYISO. The NYISO compares the PJM/NYISO Interface Price with its RTC calculated NYISO/PJM Interface Price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

CTS transactions are evaluated based on the spread bid, which limits the amount price convergence that can occur. As long as balancing operating reserve payments are applied and CTS transactions are optional, there is no reason not to proceed with the development of the CTS proposal. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be addressed to improve the efficiency of interchange transaction pricing at the PJM/NYISO seam. Minimizing this time lag is more likely to improve pricing efficiency at the PJM/NYISO border than the CTS transaction approach.

Elimination of Sources and Sinks

The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets. On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving non-firm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

Total uncollected congestion charges during the first nine months of 2013 were -$2,860, compared to -$32 in the first nine months of 2012 (Table 9-31). If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction. Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case for the net uncollected congestion charges in the first nine months of 2013. In other words, when market participants utilize the not willing to pay congestion product, it also means that they are not willing to receive congestion credits when the LMP at the source is greater than the LMP at the sink. The fact that there was a total negative congestion collection in the first nine months of 2013, for not willing to pay congestion transactions, means that market participants who utilized the not willing to pay congestion transmission option for their transactions had transactions that flowed in the direction opposite to congestion.

The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations mostly addresses these concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be necessary in the future to address this exposure.

Table 9-31 Monthly uncollected congestion charges: January, 2010 through September, 2013

Month	2010	2011	2012	2013
Jan	$148,764	$3,102	$0	$5
Feb	$542,575	$1,567	($15)	$249
Mar	$287,417	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)
May	$41,025	$0	($27)	$0
Jun	$169,197	$1,354	$78	$0
Jul	$827,617	$1,115	$0	$0
Aug	$731,539	$37	$0	$0
Sep	$119,162	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	
Nov	$30,843	($795)	($4,678)	
Dec	$127,176	($659)	($209)	
Total	$3,314,018	($20,955)	($11,789)	($2,860)

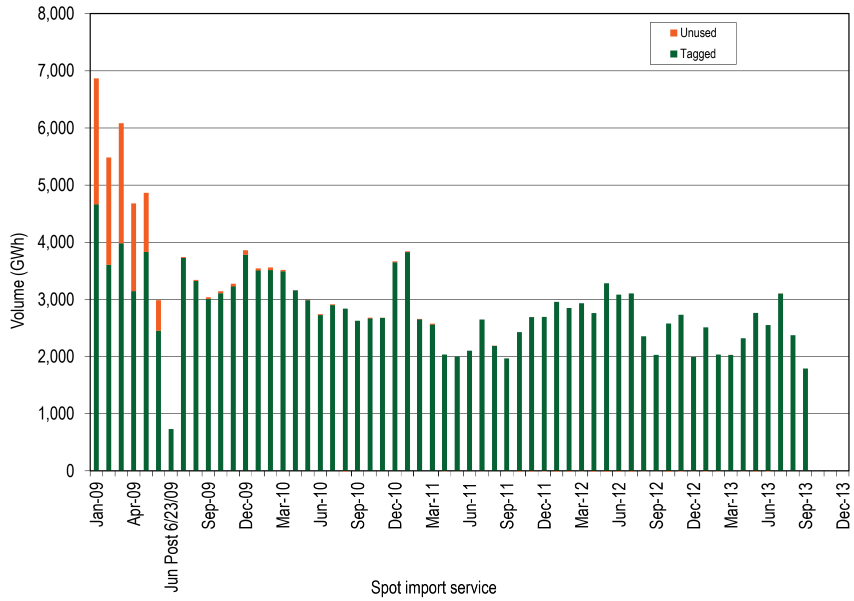
Spot Imports

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange. PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[72] The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

Due to the timing requirements to submit transactions in the NYISO market, the limitation of ATC for spot market imports at the NYISO Interface experiences the most issues with potential hoarding. The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

72 See "Modifications to the Practices of Non-Firm and Spot Market Import Service," (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>.

Figure 9-14 Spot import service utilization: January, 2009 through September, 2013



Real-Time Dispatchable Transactions

Real-Time Dispatchable Transactions, also known as “real-time with price” transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction.

Dispatchable transactions were a valuable tool for market participants when implemented. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants, but the risk to other market participants is substantial, as they are subject to paying the resultant operating reserve credits.

Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. There have been no balancing operating reserve credits paid to dispatchable transactions since July, 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that no dispatchable schedules were submitted during the first nine months of 2013.

Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of incentive rates or cost.[2]

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve and Non-Synchronized Reserve Markets, and the PJM DASR Market for the first nine months of 2013.

Table 10-1 The Regulation Market results were indeterminate for January through September, 2013

	January through September 2013	
Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	To Be Determined	To Be Determined

- The Regulation Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 91 percent of the hours in January through September, 2013.
- Participant behavior in the Regulation Market was evaluated as competitive for January through September, 2013 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as indeterminate, after the introduction of the new market design. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design are inefficient and because there is not yet enough information on performance.
- Market design was evaluated as indeterminate, after the introduction of the new market design. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. The market design also includes the incorrect definition of the marginal benefits factor for purposes of settlement.[3] It is too early to reach a definitive conclusion about the new market design because there is not yet enough information about actual implementation of the design.

Table 10-2 The Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration. The MMU estimates that the Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 5.6 percent of the hours in January through September, 2013.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.

1 75 FERC ¶ 61,080 (1996).
2 For more details, see the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

3 On October 2, 2013 FERC issued an order directing PJM to compensate regulating resources (the portion of each resource's compensation based on performance) based on a mileage ratio multiplier. This ratio will be the hourly mileage of the RegD signal / mileage of the RegA signal. This ratio increases the regulation performance compensation paid to high performing resources compared with regular resources. Between October 2012 and September 2013 the average mileage ratio has been 3.11 compared to an average marginal benefit factor of 2.63. PJM will begin to settle the regulation market (performance segment) using the mileage ratio on November 1, 2013. PJM will then recalculate performance regulation settlement for the purpose of adjusting the credits from October 1, 2012, through October 31, 2013. The regulation performance clearing price will not change.

- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in competitive prices.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 10-3 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), 15 percent of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test, and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Overview

Regulation Market

The PJM Regulation Market continues to be operated as a single market.

Market Structure

- **Supply.** In January through September 2013, the supply of offered and eligible regulation in PJM was both stable and adequate. The ratio of offered and eligible regulation to regulation required averaged 3.67. This is a 14.7 percent increase over January through September 2012 when the ratio was 3.20.
- **Demand.** The on-peak regulation requirement is equal to 0.70 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 0.70 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in January through September, 2013, was 784 MW. This is a 214 MW decrease in the average hourly regulation demand of 998 MW in the same period of 2012.
- **Market Concentration.** In January through September 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 2063 which is classified as highly concentrated.[4] In January through September 2013, 91 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (44 percent of hours failed the three pivotal supplier test in January through September 2012).

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. The performance offer is converted to $/MW by multiplying the MW offer by the ΔMW/MW value of the signal type

4 See the *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

of the unit. Owners must also specify which signal type the unit will be following, RegA or RegD.[5] As of September 30, 2013, there were 22 resources offering performance regulation and following the RegD signal.

- **Price and Cost.** The weighted average Regulation Market Clearing Price for the PJM Regulation Market for January through September 2013 was $32.72. This is an increase of $17.80, or 119.3 percent, from the weighted average price for regulation in January through September 2012. The cost of regulation from January through September 2013 was $37.35. This is a $16.77 (81.5 percent) increase from the same time period in 2012.

Synchronized Reserve Market

Although PJM has retained the two synchronized reserve markets it implemented on February 1, 2007, their definition has changed. The RFC Synchronized Reserve Zone has incorporated the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated the Dominion Zone to become the Mid-Atlantic Dominion Reserve Zone. PJM has the right to define new zones or subzones "as needed for system reliability."[6]

Market Structure

- **Supply.** In January through September, 2013, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of Demand Response (DR) to the Synchronized Reserve Market remains significant. Demand resources are relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices.

- **Demand.** PJM made a minor change to the default hourly required synchronized reserve requirements on October 1, 2012. When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Subzone became the Mid-Atlantic Dominion Subzone on October 1, 2012, the requirement remained at 1,300 MW. The integration of East Kentucky Power Cooperative (EKPC) into PJM on June 1, 2013, had no impact on the Synchronized Reserve Market requirement because the largest contingencies remain in the Mid-Atlantic Dominion Subzone. The EKPC integration did, however, increase the availability of both Tier 1 and Tier 2 MW available throughout the RTO.

  In early June 2013, PJM implemented a modification to the way the transfer interface defines the Mid-Atlantic Dominion Subzone within the RTO Zone. The change makes calculations of the unit distribution factor (DFAX) values across the interface consistent with the way these values are calculated in the energy market. Additionally, PJM calculates the most limiting interface in real time for each market optimization, ASO, IT-SCED and RT-SCED. For most hours it is Bedington – Black Oak. The second most common limiting interface is AP South.

- **Market Concentration.** For January through September 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4372 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through September, 2012, was 3202, which is classified as "highly concentrated."[7] In January through September, 2013, 58 percent of hours had a maximum market share greater than 40 percent, compared to 45 percent of hours in January through September, 2012.

  In the Mid-Atlantic Dominion Subzone, in January through September, 2013, the MMU estimates that 5.6 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In January through September, 2012, the MMU estimates that 24 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Dominion Subzone Synchronized Reserve Market in January through September 2013 was characterized by structural market power.

5 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."
6 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 61 (June 27, 2013), p. 66.
7 See Section 3, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was $6.86 per MW in January through September, 2013, a decrease of three percent over January through September 2012. The total cost of synchronized reserves per MW in January through September 2013 was $14.82, a 35 percent increase from the $10.92 cost of synchronized reserve in January through September 2012. The market clearing price was 51 percent of the total synchronized reserve cost per MW in January through September 2013, down from 64 percent in January through September 2012.
- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in January through September period of 2013. Although supplies were always adequate to meet demand, an extended spinning event on September 10 raised concerns that the current method for estimating Tier 1 is incorrect. PJM has initiated studies designed to improve the accuracy of Tier 1 estimation. It is expected that by January 1, 2014, the amount of Tier 1 estimated, especially during periods of high demand, will decrease as a result of changes to the estimation method.

DASR

The purpose of the DASR Market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[8] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The MMU calculates that in January through September, 2013, zero hours in the DASR market would have failed the three pivotal supplier test. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.
- **Demand.** In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero, but there is an opportunity cost associated with providing DASR. As of September 30, 2013, 15 percent of offers reflected economic withholding. PJM rules require that all units with reserve capability that can be converted into energy within 30 minutes offer into the DASR Market.[9] Units that do not offer have their offers set to zero.
- **DR.** Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through September, 2013.

8 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.
9 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 144.

Market Performance

- **Price.** The weighted DASR market clearing price in January through September 2013 was $0.93 per MW. In January through September 2012, the weighted price of DASR was $0.75 per MW.

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[10]

In January through September 2013 black start charges were $80.3 million. Black start zonal charges in January through September 2013 ranged from $0.03 per MW-day in the ATSI zone (total charges were $95,492) to $10.30 per MW-day in the AEP zone (total charges were $65,557,476). For each zone, Table 10-23 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.08 per MW.

Ancillary services costs per MW of load: January through September 2002 - 2013

Table 10-4 shows PJM ancillary services costs for January through September 2002 through 2013, on a per MW of load basis. The Scheduling, System Control, and Dispatch category of costs is comprised of PJM Scheduling, PJM System Control and PJM Dispatch; Owner Scheduling, Owner System Control and Owner Dispatch; Other Supporting Facilities; Black Start Services; Direct Assignment Facilities; and Reliability*First* Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

10 OATT Schedule 1 § 1.3BB.

Table 10-4 History of ancillary services costs per MW of Load: January through September 2002 through 2013

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2002	$0.47	$0.52	$0.21	$0.00	$0.66	$1.86
2003	$0.53	$0.59	$0.23	$0.09	$0.88	$2.32
2004	$0.50	$0.64	$0.25	$0.14	$0.90	$2.43
2005	$0.78	$0.47	$0.25	$0.11	$0.88	$2.49
2006	$0.55	$0.48	$0.28	$0.07	$0.44	$1.82
2007	$0.65	$0.47	$0.29	$0.06	$0.58	$2.05
2008	$0.75	$0.34	$0.29	$0.07	$0.55	$2.00
2009	$0.36	$0.36	$0.36	$0.05	$0.47	$1.60
2010	$0.37	$0.38	$0.36	$0.06	$0.75	$1.92
2011	$0.35	$0.36	$0.39	$0.09	$0.87	$2.06
2012	$0.23	$0.44	$0.44	$0.03	$0.75	$1.89
2013	$0.27	$0.41	$0.69	$0.04	$0.66	$2.07

Conclusion

The design of the Regulation Market changed significantly effective October 1, 2012. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about performance under the new market design because there is not yet enough information on performance. It is essential that the Regulation Market incorporate the consistent implementation of the marginal benefit factor in optimization, pricing and settlement. But the experience of the last quarter of 2012 and the first three quarters of 2013 is cause for optimism with respect the performance of the Regulation Market under the new market design.

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The MMU concludes that the structure of the DASR Market was competitive in the first nine months of 2013, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

Overall, the MMU concludes that it is not yet possible to reach a definitive conclusion about the new Regulation Market design, but there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in the first nine months of 2013. The MMU concludes that the DASR Market results were competitive in the first nine months of 2013.

Regulation Market

The PJM Regulation Market continues to be operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012. On May 7, 2012, PJM switched to an improved optimizer called the Ancillary Services Optimizer (ASO). On October 1, 2012, PJM made additional technical changes to the optimized solution and, to comply with FERC Order No. 755, implemented Performance Based Regulation.[11] On November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[12]

11 For a description of the full history of the changes to the tariff provisions governing the Regulation Market, see the *2011 State of the Market Report for PJM*, Volume II, Section 9, Ancillary Service Markets."
12 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 141,134 (November 16, 2012)

Regulation Market Changes for Performance Based Regulation

Regulation is a key part of PJM's effort to minimize ACE in order to keep the reportable metrics CPS1 and BAAL within acceptable limits. On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation market rules to make use of and properly compensate a mix of fast and traditional response regulation resources."[13] Order No. 755 also sought to correct "certain practices of some RTOs and ISOs result in economically inefficient economic dispatch of frequency regulation resources."[14]

A rationale for the new market design was the assumption that new, fast response technologies could be used, in combination with traditional resources, to reduce the total amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. Order No. 755 required that the new and traditional resources be purchased in a single market, with compensation for both capacity (MW) and miles (total MW per minute measured in ΔMW/MW) provided.[15] Prior to October 1, 2012, regulation consisted of energy that could be added or removed within five minutes following a traditional (RegA) signal. On October 1, 2012, the PJM introduced a single market that included two distinct types of frequency response: RegA (traditional and slower oscillation signal) and RegD (faster oscillation signal). Within this new market design, resources can choose to follow RegA or RegD.

In a market defined in terms of units of RegA equivalent regulation service, the marginal benefits factor of all units following the RegA signal is one, while the marginal benefits factor of units following the RegD signal depends on how much RegD following resources are used. Under PJM's August 15, 2012, proposal, the benefits factor can be as high as 2.9 but never lower than zero. Effective regulation is a function of two components, the benefits factor, which itself is a function of the amount of RegD regulation already committed; and the historical performance of the unit as measured by the 100-hour average of performance scores. A unit's regulation capability MW

13 Order No. 755 at P 3. FERC ordered PJM "to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal."
14 *Id.* at P 2.
15 *Id.* at PP 99, 131 & 177

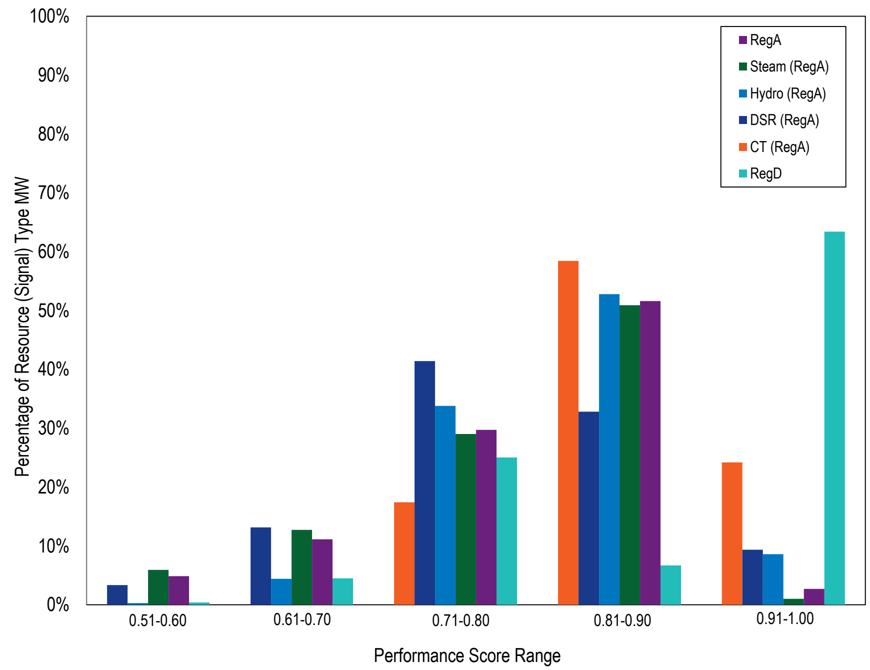
multiplied by its benefits factor, and modified by its performance score, results in that unit's effective RegA signal following regulation MW.

FERC's November 16, 2012 order only partially accepted the market design in PJM's August 15, 2012, filing. FERC's November 16, 2012, order fixed the marginal benefits factor for RegD resources at a value of 1.0 for purposes of payment. This created a dichotomy in the PJM regulation market between the marginal value of RegD resources in the dispatch, and the resulting market price and payments to resources in the settlement process in PJM's regulation market through the first quarter of 2013.

Performance tracking is an essential element of the performance based Regulation Market. Regulation performance scores (0.0 to 1.0) measure the response of a regulating unit to its chosen regulation signal (RegA or RegD) every ten seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the relationship between the regulating resource output and the regulation signal; and precision, the difference in energy provided from the difference in energy requested.[16] An hourly performance score is calculated and multiplied by the MW cleared when calculating payment. Additionally, hourly scores are stored and used as part of a 100 hour rolling average historical performance score to obtain an effective capability MW and performance MW used in clearing. Figure 10-1 shows the average performance score by unit type and signal followed.

16 A full specification of each of the three criteria used in the performance score is presented in PJM "Manual 12: Balancing Operations" Rev. 27 (December 20, 2012); 4.5.6, p 52.

Figure 10-1 Average performance score grouped by unit type and regulation signal type: January through September 2013



Using a performance score to measure the accuracy of a regulating resource, a mileage ratio to compare the effective MW of differing types of resources, and effective MW as a means of translating the value of actual MW for high performance units are the reasons that the required regulation has been lowered from 1.0 percent to 0.7 percent of forecast peak load.

The performance based Regulation Market requires that unit owners provide two-part offers for their regulation resources, an offer for regulation capability in terms of \$/MW and a regulation performance offer in terms of \$/ΔMW. In addition, unit owners must enter the regulation signal type the unit will follow, RegA or RegD. Owners may enter price based offers subject to a combined offer cap of \$100/MW.

Market Structure

Supply

Table 10-5 shows capability, average daily offer and average hourly eligible MW for all hours. The hourly regulation capability decreased in January through September 2013, to 8,411 MW from 9,413 MW during the same time period of 2012.

Table 10-5 PJM regulation capability, daily offer[17] and hourly eligible: January through September 2012 and 2013[18]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
2013 (Jan-Sep)	8,441	3,981	47%	1,716	20%
2012 (Jan-Sep)	9,413	6,656	71%	3,089	33%

The supply of regulation can be affected by regulating units retiring from service. Table 10-6 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015.

Table 10-6 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, January through September 2013	Settled MW, January through September 2013	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
306	5,125,625	33	54,484	1.06%

The cost of each unit is calculated in market clearing using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type they choose to follow, modified by resource benefit factor and historic performance score. As of October 1, 2012, a regulation resource's total offer is equal to the sum of its total capability ($/MW) and performance offer ($/MW). As of October 1, 2012, the within hour five minute clearing price for regulation is determined by the total offer, including the actual within hour lost opportunity cost, of the most expensive cleared regulation resource in each interval. The total clearing price for the hour is the simple average of the twelve interval prices within the hour. The total clearing price for the hour (RMCP) is in two parts, the performance clearing price (RMPCP) and the capability clearing price (RMCCP). The performance clearing price ($/MW) is equal to the most expensive performance offer cleared for the hour. The capability clearing price ($/MW) is equal to the difference between the total clearing price for the hour and the performance clearing price for the hour.

Since the implementation of Regulation Performance on October 1, 2012, both regulation price and regulation cost per MW are higher than they were prior to October 1, 2012 (Table 10-12). Since the implementation of shortage pricing and changing the regulation requirement to 0.70 percent of peak load forecast (from one percent of peak load forecast prior to October 1) the price and cost of regulation have remained high. The weighted average regulation price for January through September 2013 was $32.72. The regulation cost for January through June 2013 was $37.35. The ratio of price to cost is significantly higher at 88 percent (compared with 72 percent in Q3 of 2012), meaning that more of the costs are now part of the price.

As of September 30, 2013, there were 22 resources following the RegD signal. For January through September 2013, the weighted-average HHI of the set of RegD resources was 5494 (highly concentrated).

In the period from January 1, 2013, through September 30, 2013, the marginal benefit factor for cleared RegD following resources has ranged from 1.743 to 2.899 with an average over all hours of 2.595. For purposes of market settlement and payments, FERC has required PJM to set the marginal benefit factor at 1.000. Figure 10-2 shows the disparity between the actual marginal benefit factor used in clearing the Regulation Market and the FERC required marginal benefit factor used in settling the Regulation Market.

17 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
18 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

Figure 10-2 Daily (simple) average marginal benefit factor; January through September 2013

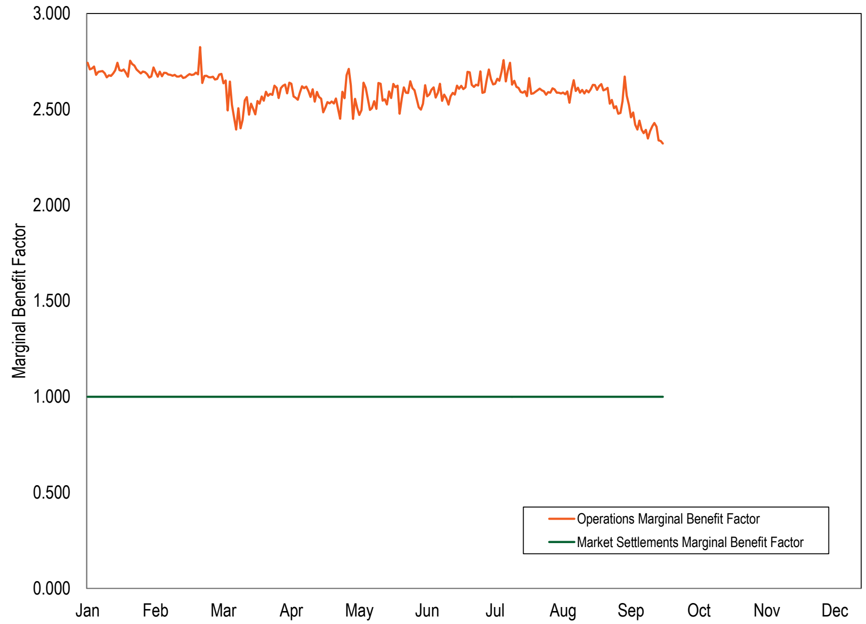
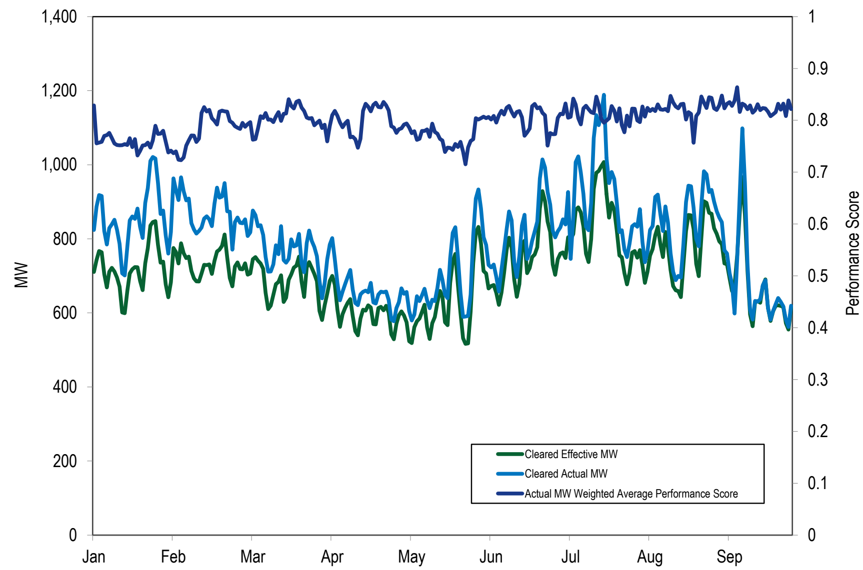
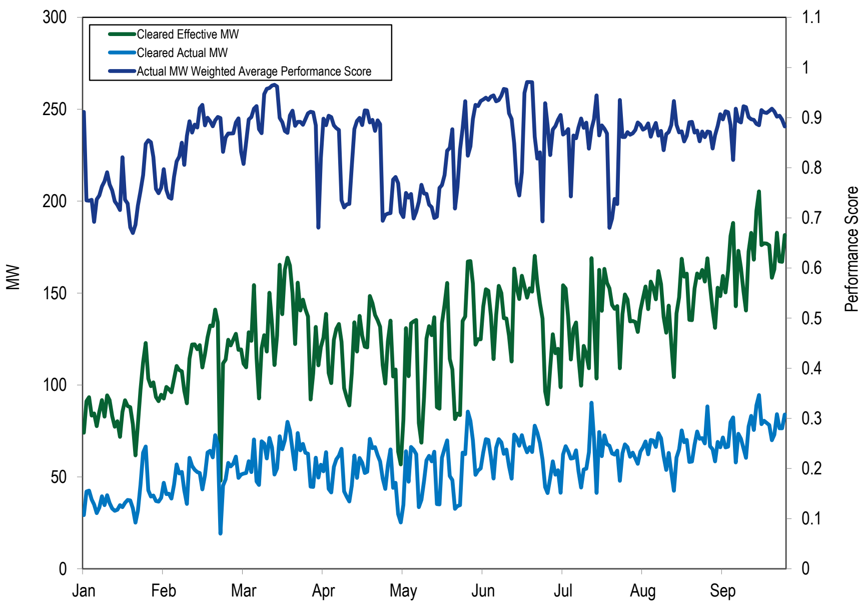


Figure 10-3 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation; January through September 2013



Although the benefits factor for traditional (RegA following) resources is 1.0, the effective MW of RegA following resources is lower than the offered MW because the performance score is less than 1 (Figure 9-2). For January through September, 2013, the MW-weighted average RegA performance score was 0.80.

Figure 10-4 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units only; January through September 2013



For RegD resources, the effective MW are higher than the actual MW because their benefits factor at current participant levels is significantly greater than 1.0 (Figure 9-3). For January through September, 2013, the MW-weighted average RegD resource performance score was 0.89.

Demand

Demand for regulation does not change with price. The regulation requirement is set by PJM in accordance with NERC control standards, based on reliability objectives and forecast load. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from one percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012. Then it was reduced to its current value of 0.70 percent of peak load forecast on December 18, 2012.

Table 10-7 shows the average hourly required regulation by month and its relationship to the supply of regulation.

Table 10-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through September 2012 and 2013

Month	Average Required Regulation (MW), 2012	Average Required Regulation (MW), 2013	Ratio of Supply to Requirement, 2012	Ratio of Supply to Requirement, 2013
Jan	1,005	851	3.29	3.66
Feb	979	870	3.45	4.65
Mar	876	766	3.14	4.86
Apr	826	656	3.19	2.55
May	918	678	3.26	3.91
Jun	1,055	801	3.21	4.34
Jul	1,246	911	2.94	1.66
Aug	1,134	832	2.97	2.60
Sep	941	693	3.33	4.80

PJM's performance as measured by CPS and BAAL standards has not declined as a result of the lower regulation requirement.[19]

19 See the *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Market Concentration

Table 10-8 shows Herfindahl-Hirschman Index (HHI) results for January through September of 2012 and 2013. The average HHI of 2063 is classified as highly concentrated and is higher than the HHI for the same period in 2012.

Table 10-8 PJM cleared regulation HHI: January through September 2012 and 2013

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013 (Jan-Sep)	730	2063	5650
2012 (Jan-Sep)	810	1529	4962

Figure 10-5 compares the 2013 HHI distribution curves with distribution curves for the same periods of 2012 and 2011.

Figure 10-5 PJM Regulation Market HHI distribution: January through September 2011, 2012, and 2013

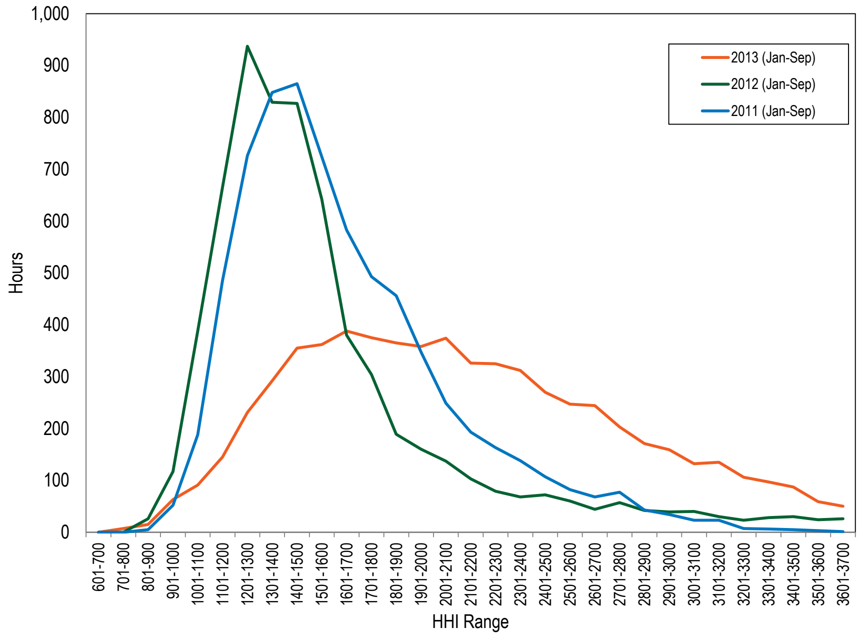


Table 10-9 includes a monthly summary of three pivotal supplier results. In January through September 2013, 91 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test.[20] Offer capping in the regulation market has little impact on prices because offers are a smaller component of price than is LOC (Figure 10-7).

The MMU concludes from these results that the PJM Regulation Market in January through September 2013 was characterized by structural market power in 91 percent of hours.

Table 10-9 Regulation market monthly three pivotal supplier results: January through September 2011, 2012 and 2013

	2013	2012	2011
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	83%	71%	95%
Feb	82%	67%	93%
Mar	97%	64%	94%
Apr	88%	41%	97%
May	93%	37%	95%
Jun	95%	40%	89%
Jul	94%	13%	89%
Aug	92%	32%	83%
Sep	90%	35%	87%

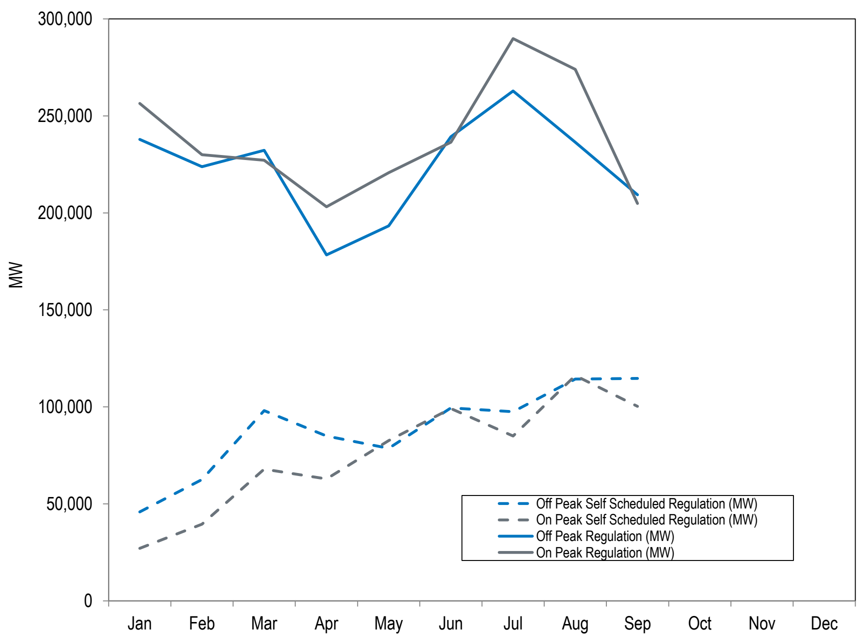
20 The MMU monitors the application of the TPS test by PJM and brings any issues to the attention of PJM.

Market Conduct

Offers

Regulation Market participation is a function of the obligation of all LSEs to provide regulation in proportion to their load share. LSEs can purchase regulation in the Regulation Market, purchase regulation from other providers bilaterally, or self-schedule regulation to satisfy their obligation (Table 10-10).[21]

Figure 10-6 Off peak and on peak regulation levels: January through September 2013



Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in January through September of 2013, 60.8 percent was purchased in the spot market, 35.5 percent was self-scheduled, and 3.7 percent was purchased bilaterally (Table 10-10).

Table 10-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through September 2012 and 2013

Year	Month	Spot Regulation (MW)	Self-Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)	RegA Regulation (MW)	RegD Regulation (MW)
2013	Jan	413,304	72,880	8,070	494,253	486,959	7,294
2013	Feb	338,990	102,005	12,808	453,803	444,689	9,113
2013	Mar	275,880	165,987	17,554	459,421	441,000	18,421
2013	Apr	219,793	147,858	13,860	381,510	365,856	15,654
2013	May	235,849	161,270	16,934	414,053	397,020	17,033
2013	Jun	254,215	198,617	22,816	475,647	456,494	19,153
2013	Jul	349,047	182,452	21,201	552,699	536,188	16,512
2013	Aug	258,550	230,441	21,351	510,342	488,951	21,391
2013	Sep	181,609	214,945	17,647	414,200	387,397	26,803
2012	Jan	553,686	164,806	21,261	739,753	NA	NA
2012	Feb	481,004	175,757	20,456	677,217	NA	NA
2012	Mar	477,564	144,408	19,683	641,655	NA	NA
2012	Apr	426,564	124,750	21,083	572,397	NA	NA
2012	May	542,585	97,574	17,849	658,008	NA	NA
2012	Jun	582,078	140,769	22,309	745,156	NA	NA
2012	Jul	819,897	63,415	19,711	903,024	NA	NA
2012	Aug	710,715	95,949	17,687	824,350	NA	NA
2012	Sep	515,732	113,351	19,726	648,809	NA	NA

Demand resources (DR) offered and cleared regulation for the first time in November 2011. In April 2012, a tariff change allowing DR to offer 0.1 MW facilitated participation by DR. In January through September 2013 DR provided an average of 1,439 MW of regulation per month.

21 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60, (June 1, 2013); para 4.1, pp 15.

Market Performance

Price

The weighted average RMCP for January through September 2013, was $32.72. This is a 119.3 percent increase from the January through September 2012 weighted average RMCP of $14.92. Figure 10-7 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market.

Figure 10-7 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through September 2013

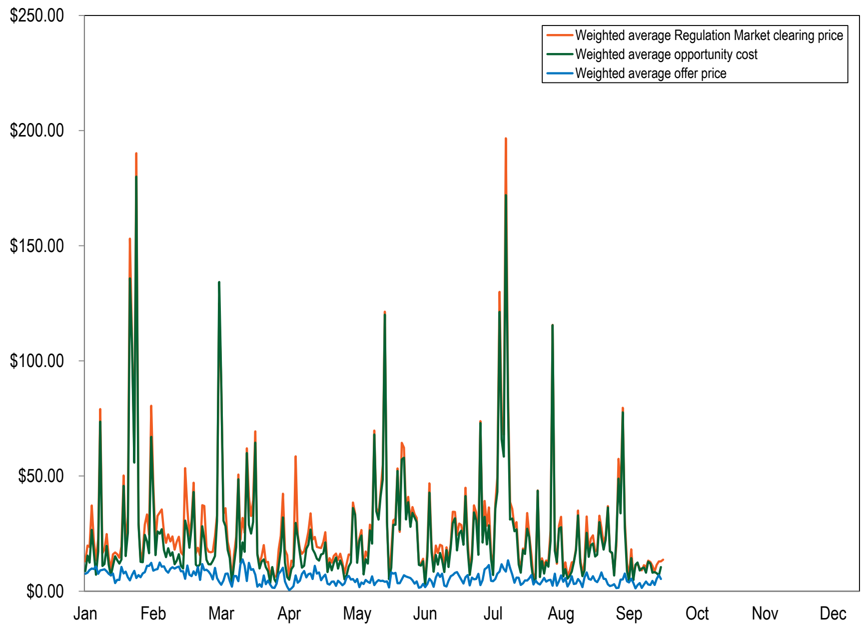


Table 10-11 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC.

Table 10-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through September 2013

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$39.94	$7.72	$39.62
Feb	$29.51	$9.37	$23.01
Mar	$31.64	$5.02	$27.10
Apr	$26.49	$5.07	$14.48
May	$33.42	$4.32	$30.52
Jun	$29.81	$4.41	$20.18
Jul	$50.12	$5.97	$32.98
Aug	$27.60	$4.30	$20.75
Sep	$25.98	$3.71	$17.44

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 10-12.

Table 10-12 Total regulation charges: January through September 2013 and 2012

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percentage of Cost
2013	Jan	494,253	$22,870,690	$39.94	$46.27	86%
2013	Feb	453,803	$15,273,604	$29.51	$33.66	88%
2013	Mar	459,421	$16,678,410	$31.64	$36.30	87%
2013	Apr	381,510	$11,930,098	$26.49	$31.27	85%
2013	May	414,053	$15,599,491	$33.42	$37.68	89%
2013	Jun	475,647	$15,999,677	$29.81	$33.64	89%
2013	Jul	552,699	$31,386,733	$50.12	$56.79	88%
2013	Aug	510,342	$15,866,117	$27.60	$31.09	89%
2013	Sep	414,200	$12,203,834	$25.98	$29.46	88%
2012	Jan	739,753	$13,338,201	$13.41	$18.03	74%
2012	Feb	677,217	$10,108,296	$11.89	$14.93	80%
2012	Mar	641,655	$11,109,763	$12.61	$17.31	73%
2012	Apr	572,397	$9,038,430	$13.01	$15.79	82%
2012	May	658,008	$16,248,950	$17.44	$24.69	71%
2012	Jun	745,156	$14,181,461	$14.91	$19.03	78%
2012	Jul	903,024	$29,228,039	$20.73	$32.37	64%
2012	Aug	824,350	$18,273,264	$15.86	$22.17	72%
2012	Sep	648,809	$13,593,245	$14.41	$20.95	69%

A breakdown of the cost of regulation into its capability, performance, and opportunity cost components is shown in Table 10-13 and a comparison of monthly average RMCP credits per Effective MW earned by RegA and RegD resources is shown in Figure 10-8.

Table 10-13 Components of regulation cost: January through September 2013

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	494,253	$33.74	$6.25	$6.28	$46.27
Feb	453,803	$25.50	$4.10	$4.06	$33.66
Mar	459,421	$28.31	$3.46	$4.53	$36.30
Apr	381,510	$23.21	$3.36	$4.69	$31.27
May	414,053	$30.44	$3.01	$4.22	$37.68
Jun	475,647	$26.80	$3.09	$3.74	$33.64
Jul	552,699	$46.08	$4.11	$6.59	$56.79
Aug	510,342	$22.93	$4.76	$3.40	$31.09
Sep	414,200	$22.02	$4.05	$3.40	$29.46

Figure 10-8 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: January through September 2013

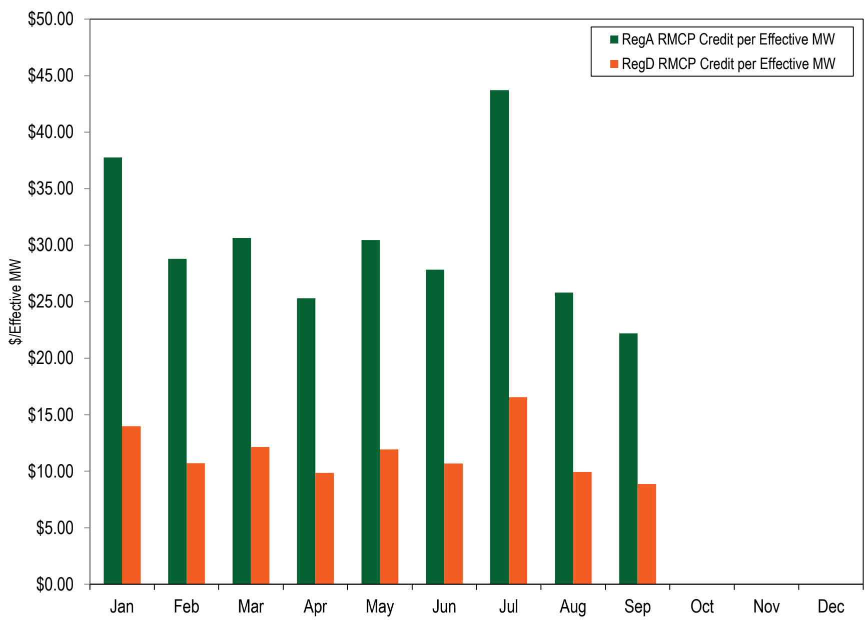


Table 10-14 provides a comparison of the average price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in January through September 2013 than it was in January through September 2012. This is an improvement which resulted from the use of pricing based on real-time LMP instead of forecast LMP as had been done prior to shortage pricing in October 1, 2012.

Table 10-14 Comparison of average price and cost for PJM Regulation, January through September 2007 through 2013

Period	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$17.03	$32.71	52%
2012	$14.92	$20.58	72%
2013	$32.72	$37.35	88%

Primary Reserve

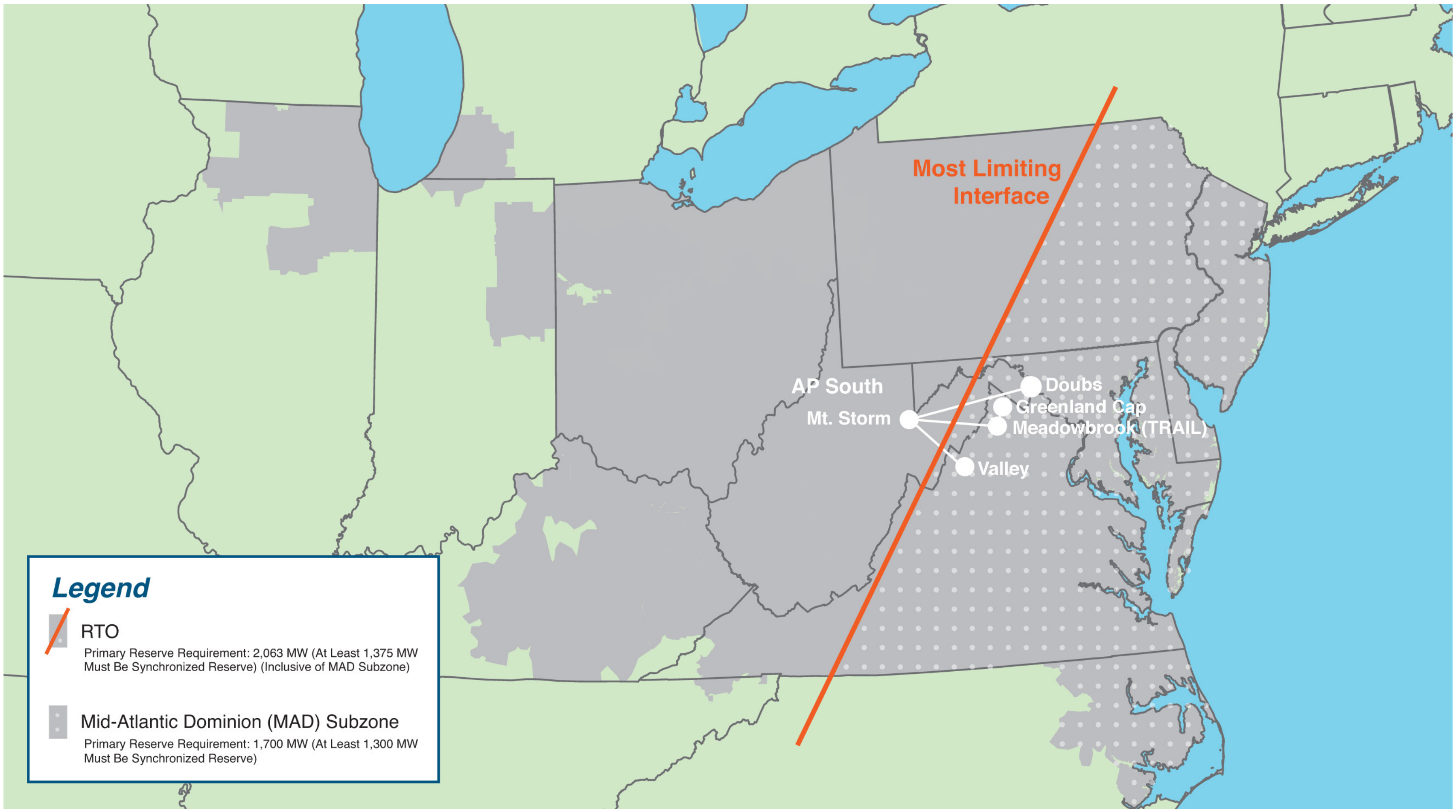
Reserves are provided by generating capability that is standing by ready for service if an unforeseen event causes a need for it. NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12.[22] NERC defines contingency reserves as energy available in 15 minutes. PJM calls this Primary Reserve and specifies it as energy available within 10 minutes. Units in a shutdown state may satisfy the primary reserve requirement if they can start within 10 minutes. PJM retains a separate ten minute synchronized reserve requirement.

22 See PJM. "Manual 12: Balancing Operations" Revision 27, Attachment D, "Disturbance Control Performance/Standard" (December 20, 2012), p. 84.

Requirements

PJM must satisfy the contingency reserve requirements specifications of the Reliability*First* Corporation and VACAR. For the RTO reserve zone the primary reserve requirement is 150 percent of the largest contingency in the PJM footprint, currently 2,063 MW. Of that 2,063 MW, PJM requires that at least 1,375 MW be on line and synchronized to the grid (Figure 10-9).

Figure 10-9 PJM RTO geography and primary reserve requirement: January through June 2013



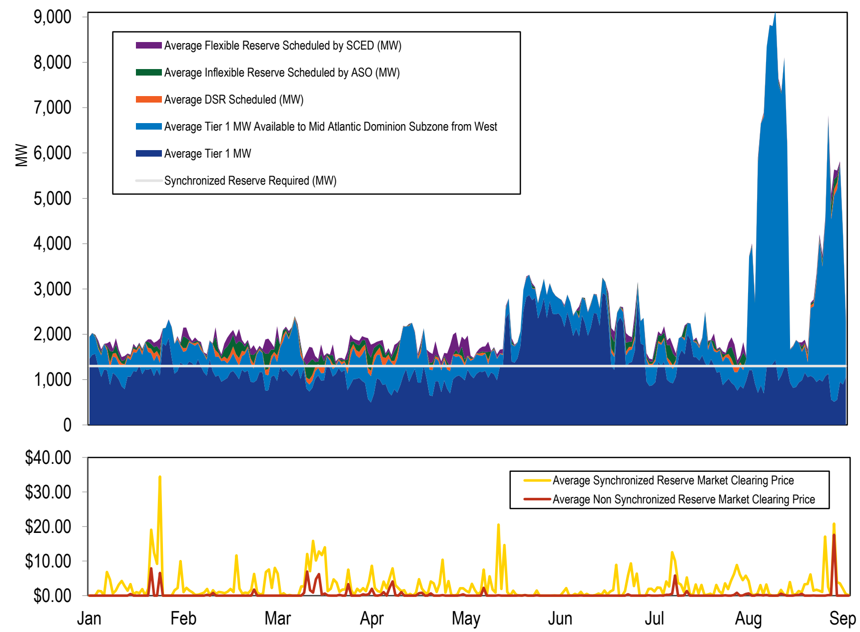
PJM recognizes that transmission constraints limit the deliverability of reserves within the RTO, and therefore creates a sub-zone within the RTO called the Mid-Atlantic Dominion Subzone. Of the 2,063 MW requirement for primary reserve in the RTO, 1,700 MW must be deliverable to the Mid-Atlantic Dominion Subzone. Of the 1,375 MW of synchronized reserve in the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion Subzone.

The primary reserve requirement is satisfied with both synchronized reserve and non-synchronized reserve, both of which are reserves available within ten minutes. Synchronized reserve is on-line and synchronized to the grid. Non-synchronized reserve is any unit not synchronized to the grid but capable of providing energy within ten minutes (examples of this are shutdown run-of-the-river hydro, pumped hydro, CTs, some CCs and diesels).

The Mid-Atlantic Dominion Subzone is defined dynamically by the most limiting constraint. In approximately 99 percent of ASO, RT-SCED, and IT-SCED cases, that constraint is Bedington - Black Oak (Figure 10-9). Between January 1, 2013, and May 31 2013, the reserve interface had been defined by the set of all resources with a three percent or greater DFAX raise help on the constrained side of the Bedington - Black Oak constraint. From June 1, 2013, through September 30, 2013, PJM determined the most limiting interface in real time and used that constraint to determine which resources were deliverable within the constrained area.[23] The effect of these changes to the reserve interface has been to significantly increase the supply of Tier 1 synchronized reserve available in the Mid-Atlantic Dominion Subzone thereby decreasing the amount of Tier 2 synchronized reserve required (Figure 10-10). On June 1, 2013, PJM integrated the East Kentucky Power Cooperative transmission system. This is on the unconstrained side of the AP South constraint.

The primary reserves requirement is not satisfied by a single market but by several products across the RTO Zone and Mid-Atlantic Dominion Subzone. The two requirements of the Mid-Atlantic Dominion Reserve Zone, primary reserve (1,700 MW) and synchronized reserve (1,300 MW) are satisfied by a set of products optimized to minimize total cost (Figure 10-10). The components of the Mid-Atlantic Dominion Primary Reserve Zone in order of increasing cost are: Tier 1 synchronized reserve available within the Mid-Atlantic Dominion Primary Reserve zone which is priced at $0 unless there is a shortage event, a spinning event or the price of non-synchronized reserve rises above zero; Tier 1 synchronized reserve available across the most limiting constraint from the west as seen by the RT-SCED which is also priced at $0; Demand Response which is always inflexible Tier 2 synchronized reserve and cleared by the ASO; inflexible Tier 2 generation reserve scheduled and priced economically by ASO; and flexible synchronized reserve scheduled by the RT-SCED.

Figure 10-10 Components of Mid-Atlantic Dominion Subzone Primary Reserve (Daily Averages): January through September, 2013



23 The specific constrained interface may be revised by PJM to meet system reliability needs. Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 78.

Figure 10-10 shows that Tier 1 Synchronized Reserve remains the major contributor to satisfying the reserve requirements. Tier 1 synchronized reserve available inside the subzone from the RTO Zone is also a major contributor to satisfying the Mid-Atlantic Dominion (MAD) subzone synchronized reserve requirement. Both of these components have a price of $0.00 unless a Tier 2 Synchronized Reserve or Non-Synchronized Reserve market is cleared in the RTO Zone. Non-synchronized reserve clears a separate market less frequently because (like DASR) it is available without redispatch from CTs, diesels and some hydro units (Ref. Non-Synchronized Reserve Market). Tier 2 synchronized reserve is dispatched at a market clearing price.

In 206 hours between January 1 and September 30, 2013, the Non-Synchronized Reserve Market for the Mid-Atlantic Dominion Subzone cleared at greater than $0.00, averaging $10.17 with a maximum clearing price of $210.07 on September 11. Non-synchronized reserve only clears when synchronized reserve also clears.

Scarcity Pricing

On October 1, 2012 PJM introduced shortage pricing, scarcity pricing, which made major changes to the structure and operation of the PJM reserve markets. PJM now has two markets to satisfy the primary reserve requirement; the Synchronized Reserve Market (Tier 2), and the new Non-Synchronized Reserve Market. The Synchronized Reserve Market dispatches Tier 2 synchronized reserve plus demand response to satisfy the synchronized reserve requirement minus the Tier 1 MW available. Both Tier 1 and Tier 2 consist of units on-line synchronized to the grid. Units offering synchronized reserve which clear the Synchronized Reserve Market are Tier 2 units. The primary reserve requirement is then satisfied by Tier 1 plus Tier 2 plus Non-Synchronized reserve.

If IT SCED and RT SCED forecast a primary reserve or synchronized reserve shortage, then PJM will implement shortage pricing through the inclusion of primary reserve or synchronized reserve penalty factors.[24]

With shortage pricing, PJM began specifying that all on-line, non-emergency, generation capacity resources must offer Tier 2 synchronized reserve in accordance with the resources' capability to provide these reserves. As of the end of September 2013 PJM through its Operations Committee is still finalizing the penalty structure for not complying with a Tier 2 commitment, as well as final manual language for the must offer provisions.

If PJM issues a Primary Reserve Warning, Voltage Reduction Warning, or Manual Load Dump Warning, all off line non-emergency generation capacity resources available to provide energy must submit an offer for Tier 2 synchronized reserve.[25] This rule ensures that IT-SCED and RT-SCED will be able to make accurate estimates of the amount of Primary Reserve available.

From January through September 2013 no reserve zone or sub-zone experienced a reserve shortage as determined by the reserve market software. However, during the September 10 spinning event an apparent real-time shortage was observed. PJM is studying this event to determine if the shortage was compliance related or if there was an actual shortage of Tier 1 MW as determined by ASO and SCED.

Synchronized Reserve Market

Prior to October 1, 2012, PJM operated two synchronized reserve markets because of differing synchronized reserve requirements specified by two different reliability regional authorities, Reliability*First* Corporation and VACAR. Those two synchronized reserve zones (Southern and RFC) are now combined into one zone, the RTO Synchronized Reserve Zone, with its requirements structured to satisfy both regional specifications.[26] Tier 2 synchronized reserve can be scheduled flexibly or inflexibly. Inflexible units are scheduled by the ASO sixty minutes before the operating hour. Inflexible units are committed to provide synchronized reserve for the entire hour and will be paid the higher of the SRMCP or their offer price plus LOC (except for demand response resources which will be paid SRMCP). Flexible units can be allocated to either synchronized reserve or to energy depending on

24 See the *2012 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets" for more details on the impact of shortage pricing on the Reserve Markets.

25 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 60, (June 1, 2013), p. 72.

26 See the *2012 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets" for more details on the impact of shortage pricing on the Synchronized Reserve Markets.

their optimal economic solution. Flexible units are assigned or re-assigned by either the IT-SCED or the RT-SCED.

Market Structure

Supply

For the first nine months of 2013, the supply of offered and eligible synchronized reserve was stable and adequate in both the RTO Zone and the Mid-Atlantic Dominion Subzone. The contribution of demand resources to the Synchronized Reserve Market remains significant. Demand resources (DR) are relatively low cost, and their participation lowers overall Synchronized Reserve prices. PJM has limited the amount of DR to 25 percent of the synchronized reserve requirement since it was introduced into the market in August 2006. On December 6, 2012, PJM increased this amount to 33 percent of the synchronized reserve requirement.

Total MW of cleared and scheduled synchronized reserve in January through September 2013 was 747,660 MW, a significant reduction from January through September of 2012, 2,097,584 MW. The DR share of the total Synchronized Reserve Market increased from 36 percent in January through September of 2012 to 42 percent in the same time period of 2013. The merging of the former Mid-Atlantic subzone with Dominion into the new Mid-Atlantic Dominion subzone, plus the changes made in June, 2013 has made more Tier 1 reserve available to the subzone (Figure 10-10). The former Dominion Zone had an excess of Tier 1, reducing the number of hours when the subzone has to clear a Tier 2 market. The ratio of offered and eligible synchronized reserve MW to the synchronized reserve required (1,300 MW) was 1.39 for the Mid-Atlantic Dominion Subzone from January through September 2013 an increase from the 1.26 ratio of offered and eligible reserve MW to required in January through September 2012.[27]

Demand

In late May and early June, PJM made several changes, both geographic and procedural, to the Synchronized Reserve Market. The reserve interface (defined by the most limiting constraint) was made dynamic with the most limiting constraint calculated in real time. In practice the result is almost always Bedington – Black Oak. In addition, the limitation of the interface was changed from calculating the effect of all units with a three percent or greater raise help on the constrained side of the interface to calculating the effect from all units. Additionally, the EKPC region was integrated into the RTO zone. These changes greatly increased the reserve available in the RTO Zone, the T1 available across the interface into the Mid-Atlantic Dominion Subzone (MAD), and the available T2 inside of MAD.

Because there is a large amount of Tier 1 available in the non-Mid-Atlantic Dominion regions of the RTO, a Synchronized Reserve Market usually does not have to be cleared in the RTO Synchronized Reserve Zone. In January through September 2013 in the RTO Synchronized Reserve Zone a Synchronized Reserve Market was cleared in less than three percent of hours (168 hours). From January through September 2013 in the Mid-Atlantic Dominion Subzone a Tier 2 Synchronized Reserve Market was cleared in 33 percent of hours at an average of 267 MW. This is a reduction from the average of 388 MW cleared in January through September 2012. It is important to note that with shortage pricing a Synchronized Reserve Market can clear at $0. The MAD Synchronized Reserve Market cleared at $0 but assigned synchronized reserve in 25 percent of hours during January through September 2013 clearing an average of 38 MW.

As of September 30, 2013, the synchronized reserve requirement for the RTO synchronized reserve zone is 1,375 MW. The Mid-Atlantic Dominion synchronized reserve zone requirement is 1,300 MW.

27 The Synchronized Reserve Market in the Southern Region between January and September, 2012 cleared in so few hours that related data for that market are not meaningful.

Table 10-15 Synchronized Reserve Market required MW, RTO Zone and Mid-Atlantic Dominion Subzone, December 2008 through June 2013

Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010		1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012		1,375

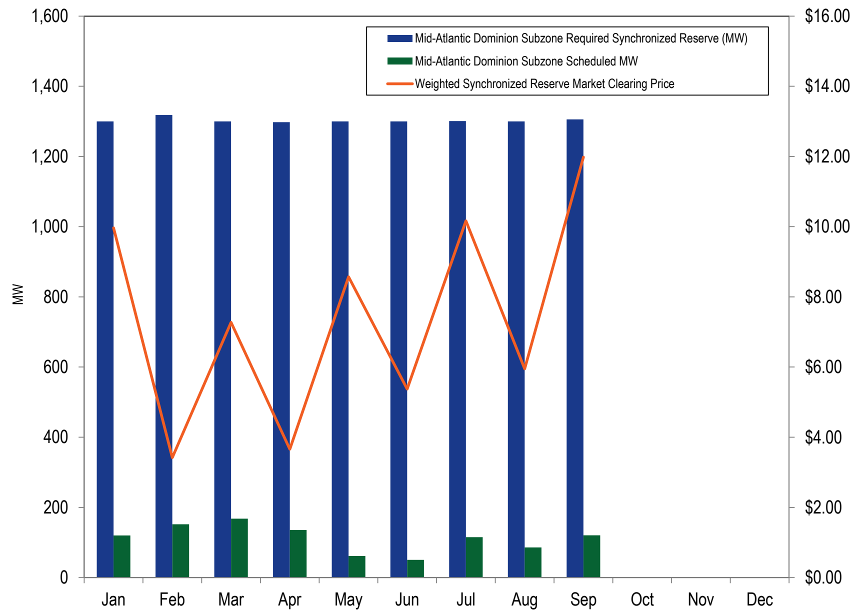
The market demand for Tier 2 synchronized reserve in the Mid-Atlantic Dominion sub-zone is determined by subtracting the amount of forecast Tier 1 synchronized reserve available plus the amount of Tier 1 available from the RTO Zone across the most limiting constraint (currently AP South) from the synchronized reserve zone's requirement each 5-minute period. Market demand is further reduced by subtracting the amount of self-scheduled Tier 2 resources.

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The requirement for both the RTO Zone and the Mid-Atlantic Dominion Subzone was raised to 1,780 MW for eight hours on February 2, 2013. The requirement for the RTO Zone was raised to 1,650 MW for 5 days from September 4 through September 8.

Figure 10-11 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through September of 2013, for the Mid-Atlantic Dominion Synchronized Reserve Market.

The RTO Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western and southern part of the RTO Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement. In January through September 2013, the RTO Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market at a price greater than $0 in 198 hours with an unweighted average SRMCP of $3.29. The Mid-Atlantic Dominion Subzone cleared a separate Tier 2 market at a price greater than $0 in 33 percent of all hours during January through September of 2013 with an unweighted SRMCP of $8.33.

Figure 10-11 Mid-Atlantic Dominion Synchronized Reserve Subzone average hourly synchronized reserve required vs. synchronized reserve scheduled MW: January through September 2013



The former Southern Synchronized Reserve Zone (integrated into the Mid-Atlantic Dominion Synchronized Reserve Zone on October 1, 2012) is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15 minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements.[28] The amount of 15 minute quick start reserve available in VACAR is sufficient to eliminate Tier 2 synchronized reserve demand for most hours. The VACAR requirement for the former Southern Synchronized

28 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 73.

Reserve Zone is now satisfied by the Synchronized Reserve requirement for the Mid-Atlantic Dominion Synchronized Reserve Subzone.

Market Concentration

The HHI from January through September 2012 for the Mid-Atlantic Subzone was 3202, which is defined as highly concentrated. The HHI for the Mid-Atlantic Dominion Subzone from January through September 2013 was 4372, which is defined as highly concentrated. Note that the HHI for 2013 includes both inflexible and flexible assigned MW. The largest hourly market share was 100 percent and 58 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 45 percent of all hours January through September 2012). Most synchronized reserve is provided by inflexible scheduled Tier 2 resources.[29] When there is not enough Tier 2 or when the IT SCED or RT SCED sees a need, flexible reserve units are assigned spinning. Flexible synchronized reserve is a much smaller market. Looking at the flexible unit sector of the synchronized reserve market from January through September, 2013, the hourly average HHI (among all resources cleared as flexible) was 8916.

The MMU estimates that in January through September, 2013, 5.6 percent of hours in the Mid-Atlantic Dominion Subzone would have failed a three pivotal supplier test (Table 9-12). This is lower than the 24 percent that the MMU calculates would have failed the three pivotal supplier test in January through September, 2012. The reason for the decline is the increasing significance of demand response in the supply of synchronized Demand response MW were 42.0 percent of the settled synchronized reserve Tier 2 MW in January through September, 2013. These results indicate that the Mid-Atlantic Dominion Sub-zone, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

29 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F, Ancillary Service Markets, Synchronized Reserve Market Clearing. With shortage pricing, PJM divided synchronized reserve into flexible and inflexible. A synchronized reserve resource can be either flexible or inflexible, but not both. Inflexible resources must be dispatched, which means incurring lost opportunity costs and/or startup and fuel costs associated with their synchronized reserve dispatch point. Flexible units can respond more quickly to a spinning event and need not be moved from their economic dispatch at the time the ASO or IT SCED runs.

Table 10-16 Mid-Atlantic Dominion Subzone[30] Synchronized Reserve Market monthly three pivotal supplier results: 2010, 2011, 2012, and 2013

Month	2013 Percent of Hours Pivotal	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	1%	45%	92%	64%
Feb	11%	40%	99%	49%
Mar	7%	38%	74%	65%
Apr	8%	33%	83%	31%
May	10%	15%	46%	45%
Jun	0%	29%	14%	10%
Jul	6%	10%	19%	23%
Aug	5%	3%	25%	18%
Sep	3%	4%	56%	17%
Oct		9%	73%	54%
Nov		17%	84%	83%
Dec		25%	88%	40%

Market Conduct

Offers

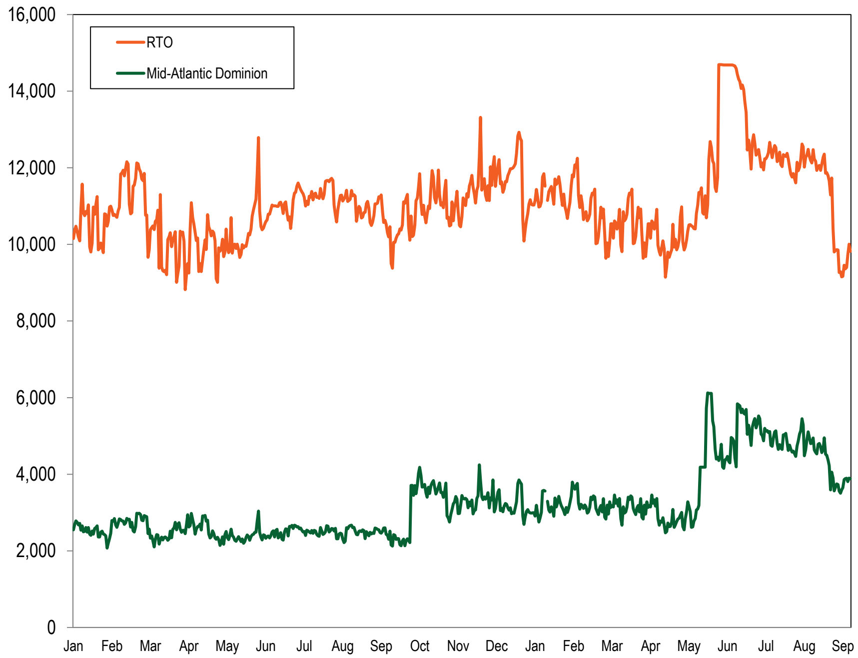
Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. Figure 10-12 shows the daily average of hourly offered Tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Sub-zone. Note that the geography of the RTO zone and the Mid-Atlantic subzone changed on October 1 with shortage pricing.

While offer volumes increased after October 1, 2012, because PJM adopted a new rule making synchronized reserve a must-offer for all generation that are on-line, non-emergency, and available for energy, compliance with this rule has been slow and subject to confusion. Beginning in late May 2013 PJM and the MMU have been reminding participants in the PJM Operating Committee

30 Note that the market expanded in October 2012 with the addition of Dominion.

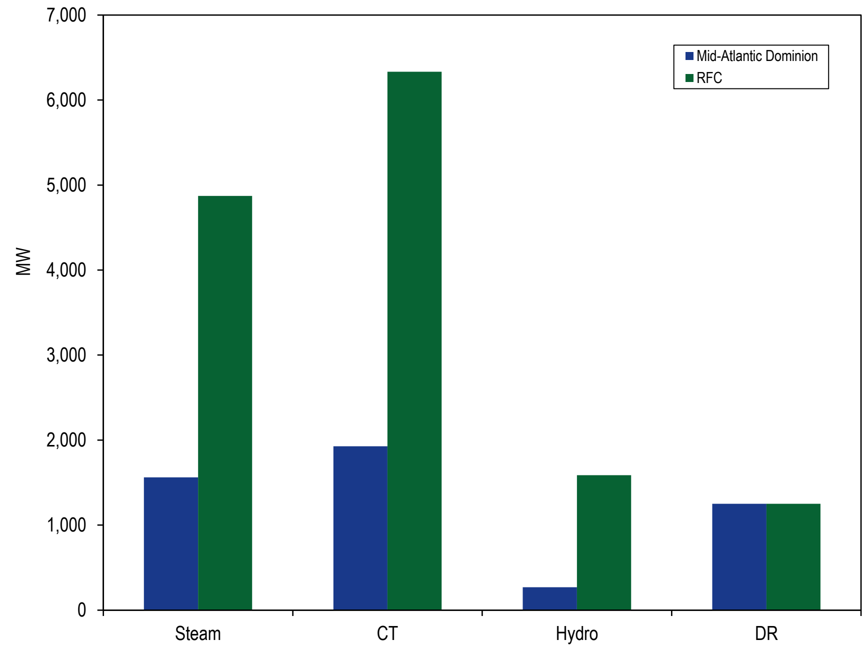
that non-emergency resources capable of providing synchronized reserve are obligated by tariff to offer their daily capability. The MMU and PJM have begun efforts to clarify the must offer rules and to make participants aware of this requirement.

Figure 10-12 Tier 2 synchronized reserve daily average offer volume (MW): January 2012 through September 2013



Synchronized reserve is offered by steam, CT, hydroelectric and DR resources. Figure 10-13 shows average offer MW volume by market and unit type.

Figure 10-13 Average daily Tier 2 synchronized reserve offer by unit type (MW): June through September 2013



DR

Demand resources were permitted to participate in the Synchronized Reserve Markets effective August 2006. DR has a significant impact on the Synchronized Reserve Market. As currently implemented in the Synchronized Reserve Market, DR is always an inflexible resource. In January through September 2013, DR was 42.3 percent of all cleared Tier 2 synchronized reserves, compared to 36 percent for the same period in 2012. In 9.4 percent of the hours in which synchronized reserve was cleared, all cleared MW was DR (Table 10-17). In the hours when all cleared MW was DR, the simple average SRMCP was $0.21. The weighted average SRMCP for all cleared hours was $6.86.

Table 10-17 Weighted average SRMCP, weighted average SRMCP when all cleared synchronized reserve is DR, and percent of all cleared hours that all cleared synchronized reserve is DR: January through September 2013 for Mid-Atlantic Dominion Sub-zone

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DR	Percent of cleared hours all synchronized reserve is DR
2012	Oct	$16.15	$1.69	2%
2012	Nov	$11.44	$0.72	4%
2012	Dec	$5.06	$0.40	5%
2013	Jan	$9.96	$0.13	7%
2013	Feb	$3.42	$0.07	5%
2013	Mar	$7.27	$0.05	12%
2013	Apr	$3.66	$0.00	11%
2013	May	$8.57	$0.25	8%
2013	Jun	$5.37	$0.00	1%
2013	Jul	$10.17	$0.07	2%
2013	Aug	$5.95	$0.67	17%
2013	Sep	$9.27	$1.49	22%

Market Performance

Price

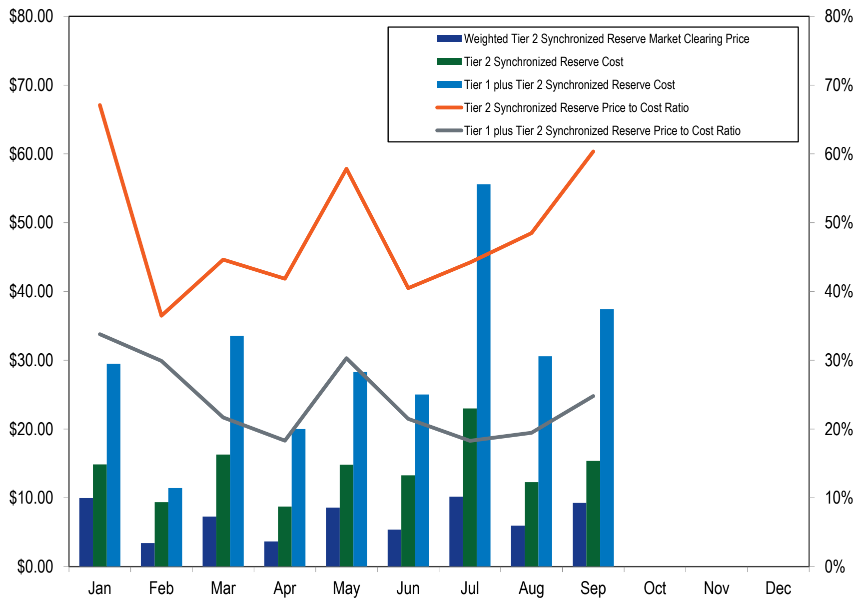
Figure 10-14 shows the weighted average Tier 2 price and the cost per MW associated with meeting synchronized reserve demand in the Mid-Atlantic Dominion Sub-zone. The price of Tier 2 synchronized reserve is the Synchronized Reserve Market Clearing Price (SRMCP).

Table 10-18 shows the monthly weighted average SRMCP, all credits including LOC credits, MW scheduled by PJM, and MW added by either the IT SCED or RT SCED for the Mid-Atlantic Dominion subzone. The weighted average price for synchronized reserve in the Mid-Atlantic Dominion Subzone in January through September 2013 was $6.86 while the corresponding cost of synchronized reserve was $14.26. The price for synchronized reserve in January through September 2012 was $7.06 while the cost was $10.96.

Table 10-18 Mid-Atlantic Dominion Sub-zone weighted synchronized reserve market clearing prices, credits, and MWs: January through September 2013

Year	Month	Weighted Synchronized Reserve Market Clearing Price	Synchronized Reserve Credits	Tier 1 Credits When NSR Prices Above $0	PJM Tier 2 and DSR Scheduled Synchronized Reserve MW	Flexible Synchronized Reserve Added by SCED (MW)	Self Scheduled MW
2013	Jan	$9.96	$1,217,854	$1,201,252	66,632	15,270	102
2013	Feb	$3.42	$1,203,289	$264,087	86,561	41,251	598
2013	Mar	$7.27	$2,275,995	$2,408,969	124,913	14,727	0
2013	Apr	$3.66	$938,914	$1,208,482	103,892	3,362	165
2013	May	$8.57	$766,400	$696,039	45,746	5,815	140
2013	Jun	$5.37	$341,359	$293,787	25,006	2,988	0
2013	Jul	$10.17	$1,781,381	$2,523,518	70,423	7,029	0
2013	Aug	$5.95	$813,309	$1,213,299	61,359	4,649	291
2013	Sep	$9.27	$1,443,551	$2,071,443	79,412	13,660	892
Total		$6.86	$10,782,052	$11,880,875	663,944	108,751	2,188

Figure 10-14 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through September 2013



The RTO Reserve Zone synchronized reserve requirement was satisfied by Tier 1 in all but 198 hours of January through September 2013. In the MAD sub-zone the Synchronized Reserve and Primary Reserve Requirements were satisfied by a combination of Tier 1 and non-synchronized reserve in 67 percent of hours from January through September 2013. In the 33 percent of hours when synchronized reserve was needed to fill the synchronized reserve and/or primary reserve requirement the maximum clearing price was $210.07 and the weighted average clearing price was $6.86.

Although Tier 1 synchronized reserve adds no cost in most hours, the change to the shortage pricing rule resulted in extremely large charges for Tier 1 reserves for a small number of hours. The rule change requires the payment of all Tier 1 reserves the full Tier 2 synchronized reserve clearing price in the hours when the non synchronized reserve market has a price greater than zero. More credits were paid to Tier 1 reserves during the 206 hours when the non-synchronized reserve price was above zero ($11.8M) than was paid to Tier 2 synchronized reserve ($10.8M) (Table 10-18) for the entire first three quarters of 2013. This is a windfall payment to Tier 1 reserves without any logical rationale.

Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient market design. In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for January through September 2013, the price of Tier 2 synchronized reserves was 49 percent of the cost. In January through September 2012, the price to cost ratio was 64 percent.

Since the implementation of shortage pricing, the price of synchronized reserve has declined slightly. The exception to this occurs when the non-synchronized reserve price is greater than $0. In that case, the shortage pricing rules require that Tier 1 synchronized reserve is paid the Tier 2 synchronized reserve clearing price. Tier 1 synchronized reserve has always been available to respond optionally to spinning events, but now it is also paid when the non-synchronized reserve price rises above zero. Payment for Tier 1 synchronized reserve that responds to a spinning event is compensated at the average of the 5-minute energy LMPs plus $50/MWh.[31] This rule significantly increases the cost of Tier 1 synchronized reserves with no operational or economic reason to do so. PJM is not actually reserving any Tier 1, but simply paying substantially more for the same product without any additional performance requirements. The MMU recommends that the rule requiring the payment of Tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. Table 10-19 shows the price and cost history of the Tier 2 Synchronized Reserve Market since 2005.

31 See PJM M-28: Operating Agreement Accounting, rev.62, 10/1/2012, p. 62.

Table 10-19 Comparison of yearly weighted average price and cost for PJM Tier 2 Synchronized Reserve, January through September 2005 through 2013

Year	Weighted Average Tier 2 Synchronized Reserve Price	Weighted Average Tier 2 Synchronized Reserve Cost	Tier 2 Synchronized Reserve Price as Percent of Cost
2005 (Jan-Sep)	$12.81	$17.01	75%
2006 (Jan-Sep)	$14.40	$27.78	52%
2007 (Jan-Sep)	$18.24	$21.27	86%
2008 (Jan-Sep)	$10.87	$16.76	65%
2009 (Jan-Sep)	$6.38	$10.41	61%
2010 (Jan-Sep)	$11.51	$16.54	70%
2011 (Jan-Sep)	$12.00	$14.21	84%
2012 (Jan-Sep)	$7.06	$10.96	64%
2013 (Jan-Sep)	$6.86	$14.26	48%

Before shortage pricing the reason for relatively low actual price to cost ratio was the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, the low price to cost ratio was in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers needed the reserves for reliability reasons (Table 10-18). The problem of lower forecast LMPs than real-time LMPs was solved by the use of real-time pricing.

Beginning with shortage pricing on October 1, 2012, PJM expanded its use of Tier 1 estimate biasing. Each market clearing engine (ASO, IT SCED, and RT SCED) can have its Tier 1 estimate manually biased. Negative Tier 1 estimate biasing refers to the manual subtraction from the Tier 1 estimate that the market clearing engines uses to determine how much Tier 2 MW to schedule. A negative bias reduces the amount of Tier 1 estimated to be available and therefore increases the amount of inflexible Tier 2 which must be purchased. PJM has reduced, but not eliminated, the use of Tier 1 estimate biasing. From July through September 2013, Tier 1 estimate was biased in 36 hours. In thirty hours of the thirty-six hours it was biased negatively averaging -236 MW. In the remaining six hours it was biased positively averaging 47 MW. The negative bias was applied entirely during several hours of the hot days of July 9 through July 19, also September 11 and September 26. During the hours of negative bias the SRMCP averaged $30.61. The average SRMCP was $2.60 during all hours between July 1 and September 30.

A negative Tier 1 bias means purchasing more inflexible Tier 2 MW than the market clearing software estimates it needs before the hour. The increased inflexible Tier 2 resources need to be compensated for their LOC and they must be paid even if they are not needed in real-time. This leads to Tier 2 synchronized reserves being assigned and paid when they are not needed or when the price is zero. A price of zero means that the Tier 2 synchronized reserve requirement was determined to be zero because there was enough Tier 1 during the hour. From January through September 2013, a total of 202,434 MW of Tier 2 synchronized reserve was purchased for hours when the price was later calculated to be $0. The charges (to compensate for lost opportunity costs) for this synchronized reserve were $986,166.

Figure 10-14 shows by month the percentage of all hours ASO had its Tier 1 estimate biased. IT SCED biasing did not occur in Q3, 2013. RT SCED Tier 1 biasing occurred in July for a total of 114 hours, averaging -305 MW and September for 147 hours averaging 317 MW. In every hour which RT SCED Tier 1 biasing was used between July and September, 2013, it was used to subtract Tier 1 from the estimate, thereby increasing the need to schedule additional Tier 2 synchronized reserve.

Figure 10-15 Impact of flexible Tier 2 synchronized reserve added by IT SCED and RT SCED to the Mid-Atlantic Dominion Subzone: January through September 2013

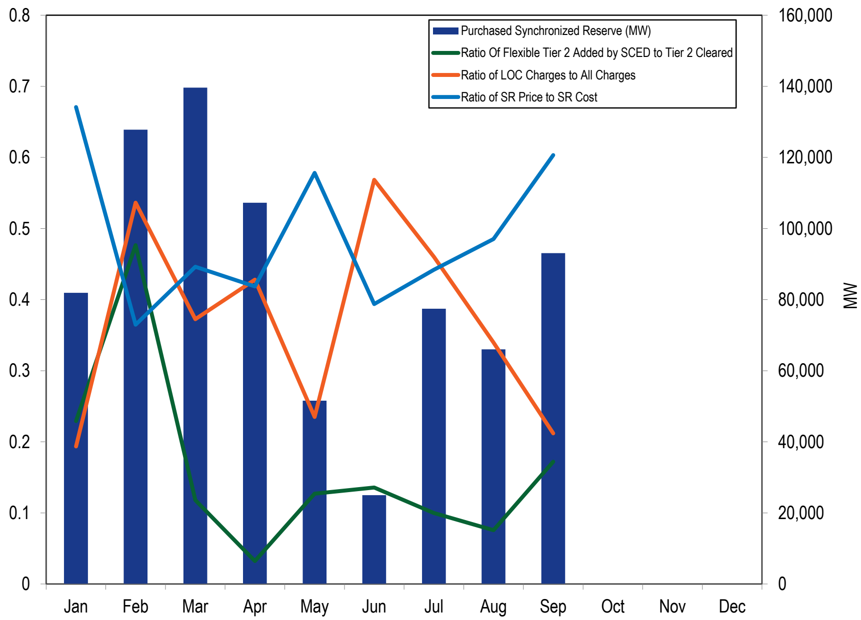
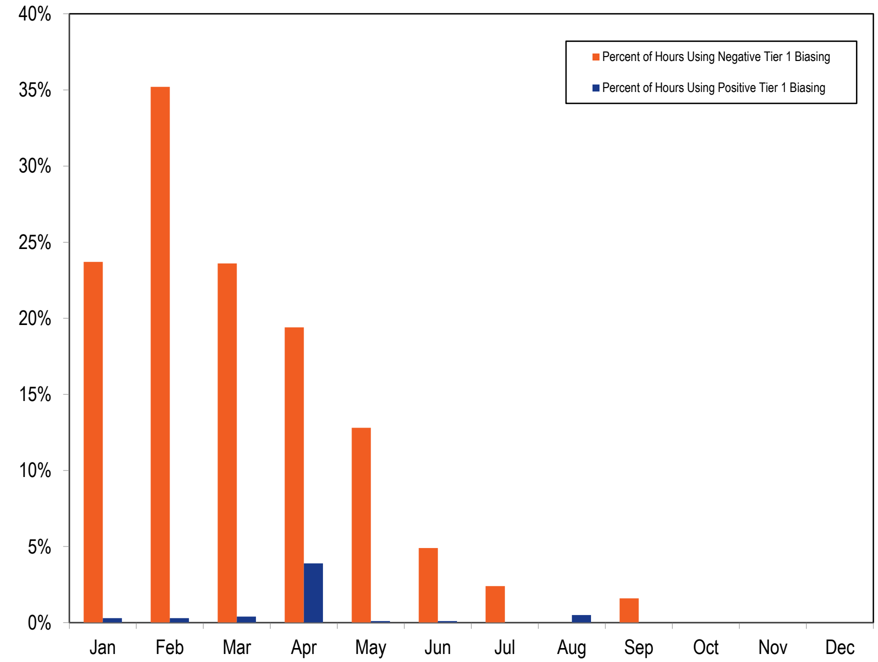


Figure 10-16 Use of ASO Tier 1 Estimate Biasing in the Middle Atlantic Dominion sub-zone: January through September 2013



PJM gives several reasons for Tier 1 estimate biasing: sometimes units do not achieve the ramp rate they have bid, sometimes units fail to follow PJM dispatch, and sometimes system conditions change rapidly during the hour between a market solution and the actual hour. But these situations occur routinely, regardless of overall system conditions. In the third quarter of 2013, Tier 1 estimate biasing was used almost exclusively during the hot days of July 10-19 and on September 11 to compensate for inaccurate estimates of Tier 1 by ASO and SCED during periods of high energy use.

The MMU recommends that PJM be more explicit about why Tier 1 biasing is used. The MMU recommends that PJM define rules for calculating available Tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.

Compliance

Non-compliance in the Synchronized Reserve Market remains a problem. Non-compliance has two major components: failure to deliver scheduled Tier 2 Synchronized Reserve MW during spinning events; and failure of non-emergency, generation resources capable of providing energy to provide a daily synchronized reserve offer.

Table 10-20 Synchronized reserve events greater than 10 minutes, July – September, 2013[32]

Q3 Qualifying Spinning Events (Hour)	Event Duration (minutes)	MAD Synchronized Reserve Market Clearing Price	Tier 2 plus DR Cleared MW	Tier 2 plus DR Added MW	Percent Tier 2 Penalized for Non Compliance	Percent of DR Penalized for Non Compliance	Overall Percent of Synchronized Reserve Penalty for Non Compliance
03-JUL-2013 20	13	$11.79	476	264	38%	49%	41%
15-JUL-2013 18	29	$7.49	361	0	14%	62%	35%
10-SEP-2013 19	68	$0.00	65	0	98%		100%

The MMU has expressed concern over noncompliance by Tier 2 synchronized reserve resources during spinning events since 2011.[33] When synchronized reserve resources clear the Synchronized Reserve Market they are obligated to provide their full cleared Tier 2 MW in a spinning event. The MMU has observed a wide range of spinning event response levels, presented its data to PJM and urged PJM to take action to increase compliance rates. In May 2013, PJM initiated an effort to increase the penalty for non-compliance of scheduled synchronized reserve resources during spinning events. As of September 30, 2013, an enhanced penalty structure was approved by the Operations Committee. The increased penalties will be implemented after FERC approval. Penalties can be assessed for any spinning event greater than 10 minutes during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. Between July 1, 2013 and September 30, 2013, three spinning events occurred that met these criteria.

For the three spinning events that occurred between July 1 and September 30, 2013, a total of 41 percent of all scheduled Tier 2 synchronized reserve MW was not delivered and therefore penalized. Of the 1,166 MW of scheduled reserve, 483 MW of failed to perform during spinning events.

32 Additional analysis of the synchronized reserve event of 10-Sep-2013 Hour 19 is available in the History of Spinning Events section.
33 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.

The shortage pricing changes introduced on October 1, 2012, included a must offer of Tier 2 Synchronized Reserve requirement for most generators under normal conditions, and an expanded set of generators under well-defined abnormal conditions related to peak load. For all hours, all on-line, non-emergency, generating resources that are providing energy and are capable of providing synchronized reserve are deemed available for Tier 1 and Tier 2 synchronized reserve and they must have an offer and be available for reserve. When PJM issues a Primary Reserve Warning, Voltage Reduction Warning, or Manual Load Dump Warning, all other non-emergency, generation capacity resources must have an offer and be available for reserve.As of September 30, the MMU estimates that at least 14 percent of eligible energy resources are not in compliance with the synchronized reserve must-offer requirement.

History of Spinning Events

Spinning events (Table 10-21) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load synchronized reserve.[34] The reserve remains loaded until system balance is recovered. From

34 See PJM. "Manual 12, Balancing Operations," Revision 27 (December 20, 2012), pp. 36-37.

January 2010 through September 2013, PJM experienced 113 spinning events, or between two and three events per month. Spinning events had an average length of 13.2 minutes.

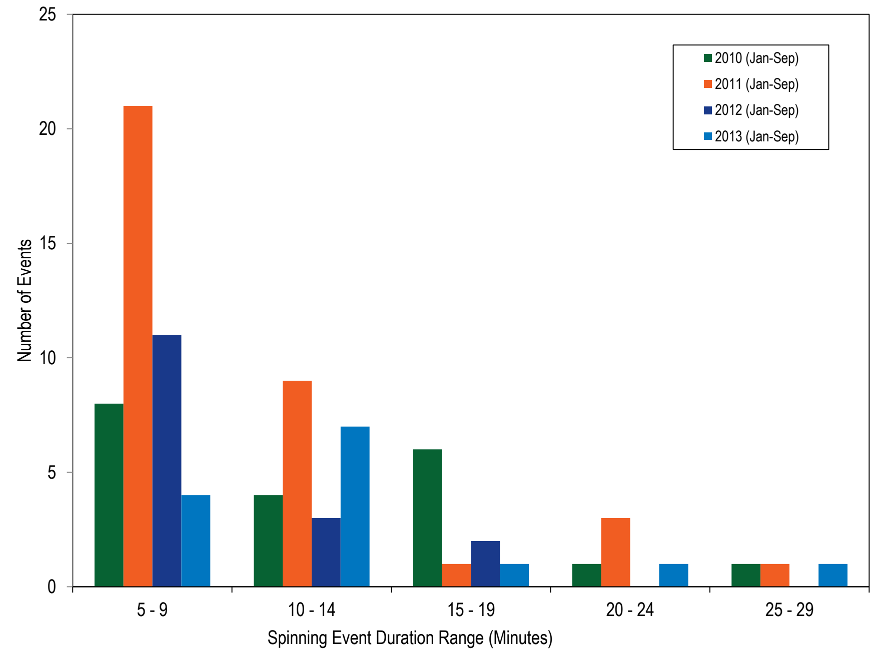
Table 10-21 Spinning Events, January 2010 through September 2013

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7			
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10			
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19			
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14			
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12			
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9			
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7			
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5			
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10						
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12						
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6						
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6						
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5						
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7						
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8						
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7						
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9						
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10						
			DEC-15-2011 14:35	Mid-Atlantic	8						
			DEC-21-2011 14:26	RFC	18						

The spinning event of September 10, called by PJM due to low ACE, lasted 68 minutes, which is the longest spinning event in at least the last five years. PJM's systems did not anticipate the event, clearing low levels of Tier 2 synchronized reserve as a result of overestimating the amount of Tier 1 available. When the event was called, resources estimated to have available Tier 1 did not respond as expected and did not resolve the imbalance. During the day of September 10, Tier 2 synchronized reserve and non-synchronized reserve prices were $0.00 for 22 hours and $3.18 and $1.53 for hours 1600 and 1700. Low ACE that is not the result of a generator outage or transmission interruption indicates a problem with short-term load forecasting, dispatch solution, reserve measurement and/or generator compliance with instructions.

September 10 was part of a three-day period of high demand for energy and reserves, September 9 through September 11. The day following the spinning event, September 11, 2013, was also a hot day. Although PJM Dispatch used Tier 1 estimate biasing in only 1.5 percent of hours from July 1 through September 30, on September 11 PJM Dispatch used it for 9 contiguous hours from 1200 to 2000 inclusive, averaging -241 MW. During this period, prices for both Tier 2 synchronized reserve and non-synchronized reserve increased to $210.07, prices for Tier 2 synchronized reserve averaged $50.83, and prices for non-synchronized reserve averaged $46.89.

Figure 10-17 Spinning events duration distribution curve, January through September 2010 to 2013



Adequacy

A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. No primary reserve shortages were identified by PJM between January 1, 2013, and September 30, 2013.

Non-Synchronized Reserve Market

The primary reserve requirement is 150 percent of the largest contingency. For the RTO Reserve Zone this is 2,063 MW. For the Mid-Atlantic Dominion Reserve Zone this is 1,700 MW. The primary reserve requirement can be filled with Tier 1 synchronized reserve, Tier 2 synchronized reserve, or non-synchronized reserve subject to the requirement that there be 1,300 MW of synchronized reserve in the Mid-Atlantic Dominion Reserve Zone. The Ancillary Services Optimizer determines the most economic combination of these products to fill the balance of the primary reserve requirement. As such there is no pre-defined hourly requirement for non-synchronized reserve.

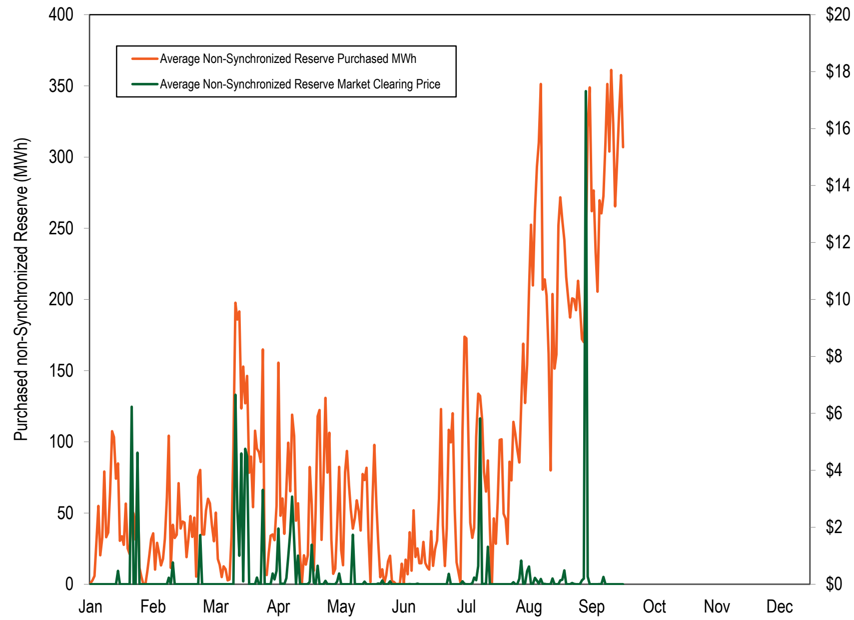
Non-synchronized reserve is reserve MW available within ten minutes but not synchronized to the grid. PJM specifies that 1,300 MW of synchronized reserve must be available in the Mid-Atlantic Dominion Reserve Zone. The remainder can be made up of non-synchronized reserve. Examples of equipment that generally qualify in this category are shutdown run-of-river, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle and diesels.[35]

As for Tier 1 synchronized reserve, PJM calculates the amount of non-synchronized reserve available each hour and every five minutes within the hour. The calculation is based upon a unit's startup and notification time, energy ramp rate, and economic minimum. Almost all non-synchronized reserve enabled resources are CTs, with some Diesel. Startup time for these units is not subject to testing. There is no non-synchronized reserve offer price. Prices are determined by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. In most hours the non-synchronized reserve clearing price is zero.

Figure 10-18 shows the daily average non-synchronized reserve market clearing price and average scheduled MW. The Mid-Atlantic Dominion Reserve Zone non-synchronized reserve market cleared with a clearing price greater than zero in 206 hours from January through September of 2013 with a maximum of $210.07 on September 11, 2013. The non-synchronized reserve market clearing price for the RTO Reserve Zone cleared in 64 hours with a maximum clearing price of $9.22 on August 31, 2013.

35 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 60 (June 1, 2013), p. 85.

Figure 10-18 Daily average Non-Synchronized Reserve Market clearing price and MW purchased: January through September 2013



While the overall impact of non-synchronized reserve on Primary Reserve costs remains low (with an average price of $10.17 for the 206 hours when it cleared above $0 between January and September) the non-synchronized reserve market includes a tariff change that significantly increases the cost and does so in an uneconomic way. Whenever non-synchronized reserve clears at a price above $0.00, all Tier 1 resources is paid the synchronized reserve market clearing price.[36] This new rule added $11,880,825 to the total cost of primary reserve during the January through September, 2013 period, more that the full cost of synchronized reserve for the entire period ($10,782,052).

36 See PJM. "Manual 28, Operating Agreement Accounting," Revision 60 (June 1, 2013), p. 37.

Day Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[37]

The DASR 30-minute reserve requirements are determined by the reliability region.[38] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[39] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.[40] The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2012 the load forecast error increased from 1.97 percent to 2.13 percent. The forced outage rate decreased from 4.93 percent to 4.66 percent. Added together, the 2013 DASR requirement is 6.91 percent. The DASR MW purchased averaged 6,895 MW per hour for January through September 2013, a slight decrease from 7,019 MW per hour in the same period of 2012.

In January through September, 2013, no hours failed the three pivotal supplier test in the DASR Market. No hours failed the three pivotal supplier test, calculated by the MMU, in January through September, 2012.

Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. No demand side resources cleared the DASR market in January through June, 2013.

37 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
38 See PJM. "Manual 13, Emergency Requirements," Revision 53 (June 1, 2013), p. 11.
39 See PJM. "Manual 10, Pre-Scheduling Operations," Revision 27 (February 28, 2013), pp. 18-19.
40 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[41] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. However, there is a positive opportunity cost in addition to this direct marginal cost, which is not part of the offer price but calculated by PJM. As of September 30, 2013, 15 percent of all units offered DASR at levels above $5 per MW. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

Market Performance

For 89 percent of hours in January through September, 2013, DASR cleared at a price of $0.00 (Figure 10-19). For January through September 2013, the weighted DASR price was $0.93. The highest price was $230.10 on July 17, 2013. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of offer price. When the DASR clearing price is greater than $0, 66 percent of the time the price consists solely of the offer price. The breakdown of price into offer and LOC is in Figure 10-19.

41 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 60 (June 1, 2013), p. 143.

Table 10-22 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September 2012 and 2013

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
2013	Jan	6,965	$0.00	$2.00	$0.01	5,182,020	$45,337
2013	Feb	6,955	$0.00	$0.75	$0.00	4,673,491	$20,062
2013	Mar	6,543	$0.00	$1.00	$0.02	4,861,811	$75,071
2013	Apr	5,859	$0.00	$0.05	$0.00	4,218,720	$8,863
2013	May	6,129	$0.00	$23.37	$0.20	4,560,238	$873,943
2013	Jun	7,262	$0.00	$15.88	$0.12	5,228,554	$615,557
2013	Jul	8,129	$0.00	$230.10	$6.76	6,015,476	$37,265,364
2013	Aug	7,559	$0.00	$1.00	$0.01	5,623,824	$55,766
2013	Sep	6,652	$0.00	$119.62	$1.23	4,789,728	$5,245,835
2012	Jan	6,944	$0.00	$0.02	$0.00	5,166,216	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	4,716,710	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	4,591,937	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	4,214,993	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	4,829,220	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	5,366,935	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	6,520,522	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	5,956,318	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	4,805,769	$540,586

The secondary reserve requirement (DASR) is usually satisfied at no cost and with no need to redispatch energy resources. The amount of reserve available from hydro and off-line resources is relatively static. But when energy demand is high there is less hydro and fewer offline resources available. In that case the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-19 shows the impact on price when online resources must be redispatched to satisfy the DASR requirement. Figure 10-20 illustrates the relationship between DASR prices and high energy dispatch and the use of off-line resources for secondary reserve.

Figure 10-19 Hourly components of DASR clearing price: January through September 2013

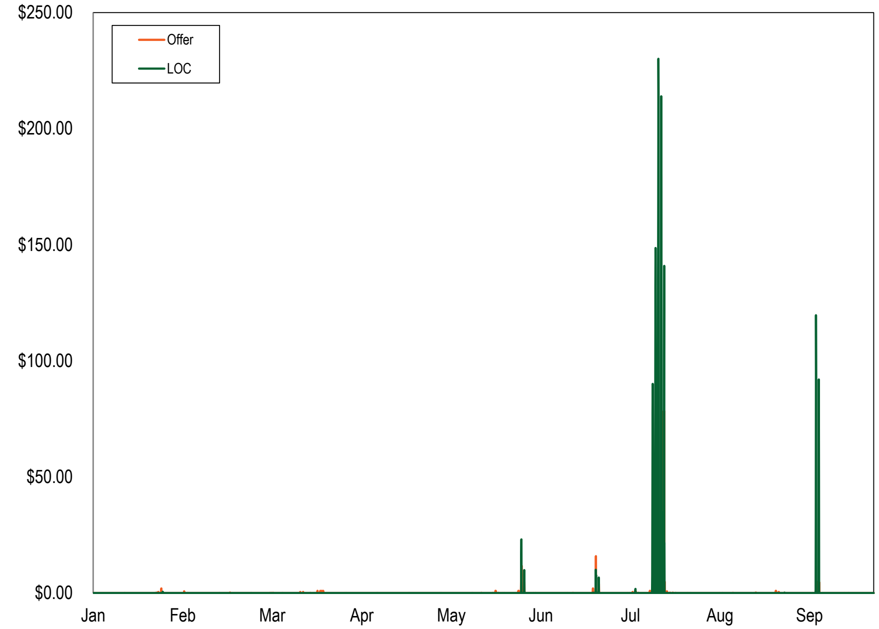
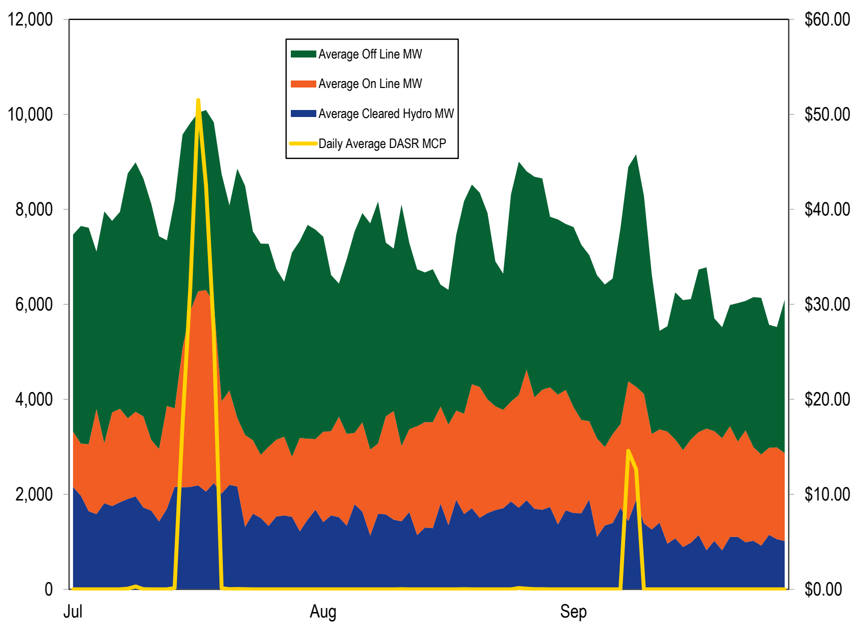


Figure 10-20 Price impact of dispatched online resources



Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners. (Table 10-23)

Following a stakeholder process in the System Restoration Strategy Task Force (SRSTF), substantial changes to the black start restoration and procurement strategy were introduced. The PJM and MMU proposal for system restoration was approved at the February 28, 2013, Markets and Reliability Committee (MRC).

The proposed changes include allowing PJM more flexibility in procuring black start resources by allowing cross zonal coordination between transmission zones, clarifying the responsibility for black start resources selection, revising the timing requirement for black start from 90 minutes to three hours, and implementing a process to revise black start plans on a five year basis in order to ensure system restoration needs are met. This proposal is a substantial improvement to current system restoration strategy, which does not give PJM adequate flexibility in procuring black start resources. This proposal also clarifies that PJM is the entity responsible for selecting the appropriate black start resources for each transmission zone based on system restoration requirements.

Black start payments are non-transparent payments made to units on the behalf of load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent the publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.

In January through September 2013, black start charges were $80.3 million. Black start zonal charges in January through September 2013 ranged from $0.03 per MW-day in the ATSI zone (total charges were $95,492) to $10.30 per MW-day in the AEP zone (total charges were $65,557,476). For each zone, Table 10-23 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.08 per MW of reserve capacity.

Table 10-23 Black start zonal charges for network transmission use: January through September 2013

Zone	Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)
AECO	$464,890	766,857	$0.61
AEP	$65,557,476	6,363,248	$10.30
AP	$182,452	2,327,134	$0.08
ATSI	$95,492	3,689,568	$0.03
BGE	$4,905,081	1,911,546	$2.57
ComEd	$3,060,666	6,443,046	$0.48
DAY	$184,311	957,438	$0.19
DEOK	$388,067	1,487,339	$0.26
DLCO	$51,327	833,769	$0.06
DOM	$254,195	1,770,908	$0.14
DPL	$433,745	1,123,149	$0.39
EKPC	$122,585	290,702	$0.42
JCPL	$423,749	1,697,896	$0.25
Met-Ed	$611,005	828,937	$0.74
PECO	$1,063,357	2,333,877	$0.46
PENELEC	$389,848	793,884	$0.49
Pepco	$236,474	1,834,751	$0.13
PPL	$146,763	2,015,150	$0.07
PSEG	$1,680,463	2,858,255	$0.59
RECO	$0	NA	NA

Congestion and Marginal Losses

The Locational Marginal Price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up of three components: the system marginal price or energy component (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).[1]

SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Total system-wide transmission losses for the first nine months of 2013 were 13,218 GWh, a 3.4 percent increase compared to the first nine months of 2012. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and higher cost units in the constrained area must be dispatched to meet that load.[2] The result is that the price of energy in the constrained area is higher than in the unconstrained area.

Congestion is neither good nor bad but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.[3,4]

Overview

Energy Cost

- **Total Energy Costs.** Total energy costs in the first nine months of 2013 decreased by $85 million or 19.2 percent from the first nine months of 2012, from -$442.6 million to -$527.6 million. Day-ahead net energy costs in the first nine months of 2013 decreased by $171.9 million or 40.0 percent from the first nine months of 2012, from -$429.8 million to -$601.6 million. Balancing net energy costs in the first nine months of 2013 increased by $98.9 million or 478.0 percent from the first nine months of 2012, from -$20.7 million to $78.2 million.
- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in the first nine months of 2013 ranged from -$90.8 million in July to -$46.5 million in April.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first nine months of 2013 increased by $39.4 million or 5.2 percent from the first nine months of 2012, from $757.6 million to $796.9 million. Day-ahead net marginal loss costs in the first nine months of 2013 increased by $95.5 million or 12.3 percent from the first nine months of 2012, from $776.0

1 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat DEOK as part of MISO for the first hour of January 2012 and as part of PJM for the second hour of January through December 2012. The metrics reported in this section treat EKPC as part of MISO for the first hour of June 2013 and as part of PJM for the second hour of June through June 2013.

2 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

3 The total marginal loss and congestion results were calculated as of October 14, 2013, and are subject to change, based on continued PJM billing updates.

4 For more details on the concepts in this section, see the *2012 State of the Market Report for PJM, Volume II:* Section 10, "Congestion and Marginal Losses."

million to $871.5 million. Balancing net marginal loss costs decreased in the first nine months of 2013 by $56.1 million or 303.8 percent from the first nine months of 2012, from -$18.5 million to -$74.6 million.

- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in the first nine months of 2013 ranged from $66.2 million in April to $142.1 million in July.
- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[5] The marginal loss credits decreased in the first nine months of 2013 by $46.0 million or 14.7 percent from the first nine months of 2012, from $313.3 million to $267.3 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $83.5 million or 19.6 percent, from $425.2 million in the first nine months of 2012 to $508.7 million in the first nine months of 2013.[6]
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $197.3 million or 32.7 percent, from $603.2 million in the first nine months of 2012 to $800.5 million in the first nine months of 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $113.8 million or 63.9 percent from -$178.0 million in the first nine months of 2012 to -$291.8 million in the first nine months of 2013.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2013 ranged from $27.8 million in March to $109.2 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the West interface, the ATSI interface, the Bridgewater - Middlesex line, the Cloverdale transformer. (Table 11-27)
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first nine months of 2013. Day-ahead congestion frequency increased by 54.1 percent from 168,509 congestion event hours in the first nine months of 2012 to 259,605 congestion event hours in the first nine months of 2013. Day-ahead, congestion-event hours increased on all types of congestion facilities.

  Real-time congestion frequency decreased by 6.0 percent from 15,153 congestion event hours in the first nine months of 2012 to 14,249 congestion event hours in the first nine months of 2013. Real-time, congestion-event hours increased on the interfaces and the flowgates, while congestion on the transformers, and the transmission lines decreased.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first nine months of 2013, for only 2.0 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first nine months of 2013, for 37.9 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

  The AP South Interface was the largest contributor to congestion costs in the first nine months of 2013. With $144.1 million in total congestion costs, it accounted for 28.3 percent of the total PJM congestion costs in the first nine months of 2013. The top five constraints in terms of congestion costs together contributed $183.8 million, or 36.1 percent, of the total PJM congestion costs in the first nine months of 2013. The

5 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60 (June 1, 2013). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.
6 The total zonal congestion numbers were calculated as of October 14, 2013, and are based on continued PJM billing updates, subject to change.

top five constraints were the AP South interface, the West interface, the ATSI interface, the Bridgewater – Middlesex line, and the Cloverdale transformer.

- **Zonal Congestion.** ComEd was the most congested zone in the first nine months of 2013. ComEd had -$337.8 million in total load costs, -$472.5 million in total generation credits and -$14.1 million in explicit congestion, resulting in $120.5 million in net congestion costs, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The Nelson – Cordova line, the Byron - Cherry Valle flowgate, the AP South interface, the Braidwood transformer, and the Crete - St Johns Tap flowgate contributed $44.1 million, or 36.6 percent of the total ComEd Control Zone congestion costs.

  The AEP Control Zone was the second most congested zone in PJM in the first nine months of 2013, with $76.5 million. The AP South interface contributed $21.0 million or 27.4 percent of the total AP Control Zone congestion cost in first nine months of 2013. The AP Control Zone was the third most congested zone in PJM in the first nine months of 2013, with a cost of $74.3 million.

- **Ownership.** In the first nine months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first nine months of 2013, financial companies received $84.1 million in net congestion credits, an increase of $16.8 million or 25.0 percent compared to the first nine months of 2012. In the first nine months of 2013, physical companies paid $592.8 million in net congestion charges, an increase of $100.3 million or 20.4 percent compared to the first nine months of 2012.

Conclusion

Energy costs are the incremental costs to the system, which are the same at every bus for each hour, without taking losses and congestion into account.

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Marginal loss costs had been decreasing since 2010, due to decreases in LMP and fuel costs. However, increases in the LMP and fuel costs have led to higher marginal loss costs in the first nine months of 2013 compared to the first nine months of 2012. Total marginal loss costs increased in the first nine months of 2013 by $39.4 million or 5.2 percent from the first nine months of 2012, from $757.6 million to $796.9 million.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities and the geographic distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 85.5 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs. FTRs were paid at 67.8 percent of the target allocation level for the 2012 to 2013 planning period, and at 77.3 percent of the target allocation level for the 2013 to 2014 planning period through September 30, 2013.[7] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

7 See the *2012 State of the Market Report for PJM, Volume II:* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014."

Locational Marginal Price (LMP)

Components

Table 11-1 shows the PJM real-time, load-weighted average LMP components for the first nine months of 2009 to 2013. The load-weighted average real-time LMP increased $4.72 or 13.5 percent from $35.02 in the first nine months of 2012 to $39.75 in the first nine months of 2013. The load-weighted average congestion component decreased $0.03 or 74.4 percent from $0.04 in the first nine months of 2012 to $0.01 in the first nine months of 2013. The load-weighted average loss component increased $0.01 or 61.7 percent from $0.01 in the first nine months of 2012 to $0.02 in the first nine months of 2013. The load-weighted average energy component increased $4.74 or 13.6 percent from $34.97 in the first nine months of 2012 to $39.72 in the first nine months of 2013.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2009 through 2013

(Jan-Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.57	$39.49	$0.04	$0.03
2010	$49.91	$49.81	$0.06	$0.04
2011	$49.48	$49.40	$0.05	$0.03
2012	$35.02	$34.97	$0.04	$0.01
2013	$39.75	$39.72	$0.01	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for the first nine months of 2009 through 2013. The load-weighted average day-ahead LMP increased $5.20 or 15.1 percent from $34.29 in the first nine months of 2012 to $39.49 in the first nine months of 2013. The load-weighted average congestion component increased $0.02 or 15.0 percent from $0.12 in the first nine months of 2012 to $0.14 in the first nine months of 2013. The load-weighted average loss component increased $0.02 or 99.3 percent from -$0.02 in the first nine months of 2012 to -$0.00 in the first nine months of 2013. The load-weighted average energy component increased $5.16 or 15.1 percent from $34.19 in the first nine months of 2012 to $39.35 in the first nine months of 2013.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2009 through 2013

(Jan-Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$39.95	$39.50	($0.05)	($0.10)
2010	$49.12	$49.05	$0.11	($0.03)
2011	$48.34	$48.55	($0.05)	($0.16)
2012	$34.29	$34.19	$0.12	($0.02)
2013	$39.49	$39.35	$0.14	($0.00)

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 11-3 for the first nine months of 2012 and 2013. The day-ahead components of LMP for each control zone are presented in Table 11-4 for the first nine months of 2012 and 2013.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2012 and 2013

	2012 (Jan-Sep)				2013 (Jan-Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.23	$35.88	($0.01)	$1.37	$42.09	$40.26	$0.03	$1.80
AEP	$32.81	$34.39	($0.82)	($0.77)	$36.31	$39.25	($1.98)	($0.96)
AP	$34.63	$34.61	$0.12	($0.10)	$38.52	$39.43	($0.73)	($0.18)
ATSI	$33.98	$34.71	($0.91)	$0.18	$44.63	$39.50	$4.67	$0.46
BGE	$40.16	$35.29	$3.28	$1.58	$44.55	$40.05	$2.70	$1.80
ComEd	$32.35	$35.27	($1.51)	($1.41)	$34.01	$39.78	($3.83)	($1.94)
DAY	$33.97	$34.88	($1.08)	$0.17	$36.91	$39.70	($2.69)	($0.10)
DEOK	$32.41	$34.95	($1.03)	($1.52)	$35.02	$39.62	($2.65)	($1.95)
DLCO	$33.44	$34.81	($0.37)	($1.01)	$36.44	$39.58	($1.85)	($1.29)
Dominion	$37.21	$35.29	$1.62	$0.31	$41.77	$39.92	$1.56	$0.29
DPL	$39.43	$35.40	$2.41	$1.62	$43.13	$40.03	$1.10	$2.00
EKPC	NA	NA	NA	NA	$35.06	$41.33	($3.93)	($2.35)
JCPL	$36.95	$36.02	($0.25)	$1.17	$44.45	$40.77	$1.79	$1.89
Met-Ed	$35.56	$34.85	$0.31	$0.40	$40.70	$39.68	$0.24	$0.78
PECO	$36.34	$35.07	$0.46	$0.81	$40.44	$39.84	($0.48)	$1.09
PENELEC	$34.40	$34.22	($0.25)	$0.44	$39.51	$39.15	($0.24)	$0.59
Pepco	$39.18	$35.31	$2.95	$0.92	$43.72	$40.06	$2.47	$1.19
PPL	$34.57	$34.59	($0.37)	$0.35	$40.19	$39.46	$0.05	$0.68
PSEG	$36.64	$35.31	$0.09	$1.24	$45.47	$40.04	$3.73	$1.70
RECO	$36.88	$36.17	($0.43)	$1.15	$47.74	$40.89	$5.20	$1.65
PJM	$35.02	$34.97	$0.04	$0.01	$39.75	$39.72	$0.01	$0.02

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2012 and 2013

	2012 (Jan-Sep)				2013 (Jan-Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.05	$34.99	$0.51	$1.54	$42.18	$39.88	$0.54	$1.75
AEP	$32.36	$33.84	($0.56)	($0.92)	$36.92	$39.09	($1.26)	($0.91)
AP	$34.01	$33.92	$0.16	($0.07)	$38.47	$39.09	($0.40)	($0.23)
ATSI	$33.09	$34.00	($0.78)	($0.13)	$38.50	$39.24	($0.98)	$0.24
BGE	$39.53	$34.62	$3.00	$1.90	$44.82	$39.72	$3.39	$1.71
ComEd	$31.08	$34.41	($1.56)	($1.77)	$34.84	$39.53	($2.93)	($1.76)
DAY	$33.46	$34.30	($0.75)	($0.09)	$37.65	$39.48	($1.65)	($0.18)
DEOK	$31.87	$34.20	($0.59)	($1.73)	$35.94	$39.24	($1.60)	($1.70)
DLCO	$32.92	$34.13	($0.16)	($1.05)	$36.67	$39.33	($1.37)	($1.29)
Dominion	$36.40	$34.56	$1.35	$0.49	$42.02	$39.71	$2.15	$0.16
DPL	$38.72	$34.80	$1.85	$2.07	$43.19	$39.65	$1.57	$1.97
EKPC	NA	NA	NA	NA	$36.83	$41.03	($1.92)	($2.28)
JCPL	$36.58	$35.01	$0.24	$1.33	$43.63	$40.13	$1.71	$1.78
Met-Ed	$34.73	$33.96	$0.26	$0.51	$40.57	$39.12	$0.82	$0.63
PECO	$35.96	$34.38	$0.60	$0.98	$40.71	$39.41	$0.28	$1.02
PENELEC	$33.97	$33.46	($0.00)	$0.51	$39.56	$38.57	$0.27	$0.72
Pepco	$38.14	$34.28	$2.58	$1.28	$43.51	$39.20	$3.17	$1.13
PPL	$34.00	$33.86	($0.19)	$0.33	$40.12	$39.04	$0.56	$0.52
PSEG	$36.66	$34.62	$0.53	$1.51	$45.51	$39.79	$3.98	$1.75
RECO	$36.36	$35.10	$0.02	$1.24	$46.59	$40.03	$4.92	$1.64
PJM	$34.29	$34.19	$0.12	($0.02)	$39.49	$39.35	$0.14	($0.00)

Component Costs

Table 11-5 shows the total energy, loss and congestion component costs and the total PJM billing for the first nine months of 2009 through 2013. These totals are actually net energy, loss and congestion costs.

Table 11-5 Total PJM costs by component (Dollars (Millions)): January through September of 2009 through 2013[8,9]

	Component Costs (Millions)					
(Jan-Sep)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($485)	$992	$544	$1,051	$19,927	5.3%
2010	($619)	$1,259	$1,134	$1,775	$26,249	6.8%
2011	($651)	$1,153	$875	$1,376	$28,836	4.8%
2012	($443)	$758	$425	$740	$22,119	3.3%
2013	($528)	$797	$509	$778	$25,153	3.1%

8 The Energy Costs, Loss Costs and Congestion Costs include net inadvertent charges.
9 Total PJM Billing is provided by PJM, and the MMU is not able to reproduce and verify the calculation.

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market, plus net inadvertent energy charges. Total energy costs can by more accurately thought of as net energy costs.

Ignoring interchange, total generation MWh must be greater than total load MWh in every hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy costs are negative (ignoring net interchange), with generation credits greater than load payments in every hour. These net energy costs plus net marginal loss costs plus net residual market adjustments, equal the marginal loss surplus which is distributed to load and exports.[10]

The total energy cost for the first nine months of 2013 was -$527.6 million, which was comprised of load energy payments of $32,756.4 million, generation energy credits of $33,279.8 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$4.2 million. The monthly energy costs for the first nine months of 2013 ranged from -$90.8 million in July to -$46.5 million in April.

Total Energy Costs

Table 11-6 shows total energy component costs and total PJM billing, for the first nine months of 2009 through 2013. The total energy component costs appear low compared to total PJM billing because these totals are actually net energy costs.

Table 11-6 Total PJM costs by energy component (Dollars (Millions)): January through September of 2009 through 2013[11]

(Jan-Sep)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($485)	NA	$19,927	(2.4%)
2010	($619)	27.6%	$26,249	(2.4%)
2011	($651)	5.3%	$28,836	(2.3%)
2012	($443)	(32.0%)	$22,119	(2.0%)
2013	($528)	19.2%	$25,153	(2.1%)

Energy costs for the first nine months of 2009 through 2013 are shown in Table 11-7 and Table 11-8. Table 11-7 shows PJM energy costs by category for the first nine months of 2009 through 2013 and Table 11-8 shows PJM energy costs by market category for the first nine months of 2009 through 2013. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-6.

Table 11-7 Total PJM energy costs by category (Dollars (Millions)): January through September of 2009 through 2013

	Energy Costs (Millions)				
(Jan-Sep)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.5	$28,754.0	$0.0	$7.9	($442.6)
2013	$32,756.4	$33,279.8	$0.0	($4.2)	($527.6)

10 Net residual adjustments are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

11 The Energy Costs include net inadvertent charges.

Table 11-8 Total PJM energy costs by market category (Dollars (Millions)): January through September of 2009 through 2013

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Sep)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.9)	($99.2)	$0.0	($20.7)	$7.9	($442.6)
2013	$32,796.6	$33,398.2	$0.0	($601.6)	($40.2)	($118.4)	$0.0	$78.2	($4.2)	($527.6)

Monthly Energy Costs

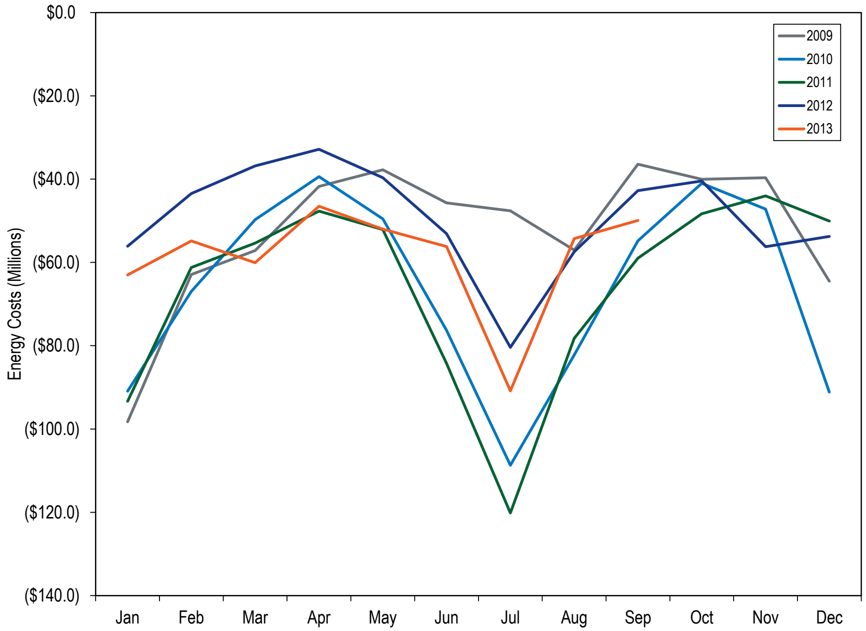
Table 11-9 shows a monthly summary of energy costs by type for the first nine months of 2012 and 2013.

Table 11-9 Monthly energy costs by type (Dollars (Millions)): January through September of 2012 and 2013

	Energy Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($48.5)	($10.1)	$2.5	($56.1)	($69.2)	$5.8	$0.5	($63.0)
Feb	($36.0)	($9.9)	$2.4	($43.5)	($60.6)	$5.9	($0.1)	($54.8)
Mar	($30.1)	($8.6)	$1.9	($36.8)	($63.9)	$4.2	($0.3)	($60.0)
Apr	($30.7)	($2.8)	$0.7	($32.8)	($46.8)	$0.9	($0.6)	($46.5)
May	($39.4)	$0.0	($0.3)	($39.7)	($48.3)	($3.4)	($0.3)	($52.0)
Jun	($57.1)	$4.0	$0.0	($53.1)	($63.4)	$7.8	($0.6)	($56.2)
Jul	($84.0)	$3.0	$0.6	($80.4)	($111.1)	$21.4	($1.1)	($90.8)
Aug	($60.3)	$2.6	$0.3	($57.4)	($71.0)	$17.4	($0.7)	($54.3)
Sep	($43.6)	$1.1	($0.2)	($42.8)	($67.3)	$18.3	($0.9)	($49.9)
Total	($429.8)	($20.7)	$7.9	($442.6)	($601.6)	$78.2	($4.2)	($527.6)

Figure 11-1 shows PJM monthly energy costs of January 2009 through September 2013.

Figure 11-1 PJM monthly energy costs (Dollars (Millions)): January 2009 through September 2013



Marginal Losses

Marginal Loss Accounting

PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system.

Total marginal loss costs, analogous to total congestion costs, are equal to the net of the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market. Total marginal loss costs can by more accurately thought of as net marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

The total marginal loss cost in PJM for the first nine months of 2013 was $796.9 million, which was comprised of load loss payments of -$3.3 million, generation loss credits of -$834.4 million, explicit loss costs of -$34.1 million and inadvertent loss charges of -$0.0 million. Monthly marginal loss costs in the first nine months of 2013 ranged from $66.2 million in April to $142.1 million in July. Marginal loss credits decreased in the first nine months of 2013 by $46.0 million or 14.7 percent from the first nine months of 2012, from $313.3 million to $267.3 million.

Total Marginal Loss Costs

Table 11-10 shows the total marginal loss component costs for the first nine months of 2009 through 2013. The yearly total loss component costs appear low compared to total PJM billing because these totals are actually net loss costs.

Table 11-10 Total PJM costs by loss component (Dollars (Millions)): January through September of 2009 through 2013[12,13]

(Jan-Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$992	NA	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%
2013	$797	5.2%	$25,153	3.2%

12 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
13 The Loss Costs include net inadvertent charges.

Total marginal loss costs for the first nine months of 2009 through 2013 are shown in Table 11-11 and Table 11-12. Table 11-11 shows PJM total marginal loss costs by category for the first nine months of 2009 through 2013. Table 11-12 shows PJM total marginal loss costs by market category for the first nine months of 2009 through 2013.

Table 11-11 Total PJM marginal loss costs by category (Dollars (Millions)): January through September of 2009 through 2013

	Marginal Loss Costs (Millions)				
(Jan-Sep)	Load Payments	Generation Credits	Explicit	InadvertentCharges	Total
2009	($62.5)	($1,028.9)	$26.1	$0.0	$992.4
2010	($71.8)	($1,299.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6
2013	($3.3)	($834.4)	($34.1)	($0.0)	$796.9

Table 11-12 Total PJM marginal loss costs by market category (Dollars (Millions)): January through September of 2009 through 2013

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Sep)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.4	($3.1)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$22.6	$7.5	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6
2013	($30.3)	($857.9)	$44.0	$871.5	$27.0	$23.5	($78.1)	($74.6)	($0.0)	$796.9

Monthly Marginal Loss Costs

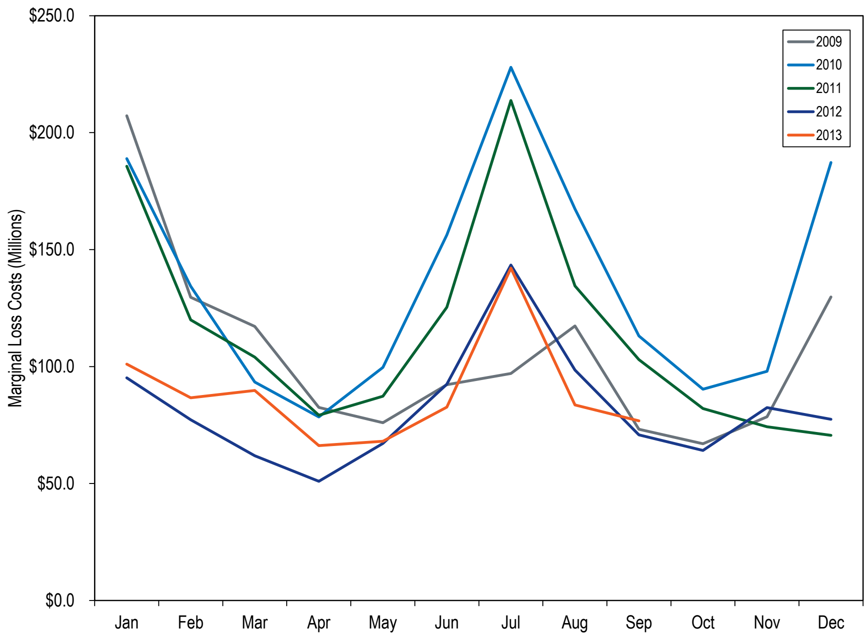
Table 11-13 shows a monthly summary of marginal loss costs by type for the first nine months of 2012 and 2013.

Table 11-13 Monthly marginal loss costs by type (Dollars (Millions)): January through September of 2012 and 2013

	Marginal Loss Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$100.6	($5.4)	$0.0	$95.2	$105.8	($4.7)	$0.0	$101.1
Feb	$80.4	($3.1)	$0.0	$77.2	$93.2	($6.5)	($0.0)	$86.7
Mar	$67.1	($5.2)	$0.0	$61.9	$97.2	($7.4)	($0.0)	$89.8
Apr	$55.4	($4.4)	$0.0	$51.0	$77.7	($11.5)	($0.0)	$66.2
May	$69.6	($2.5)	($0.0)	$67.1	$80.5	($12.4)	($0.0)	$68.1
Jun	$93.3	($0.8)	$0.0	$92.5	$91.7	($9.0)	($0.0)	$82.7
Jul	$141.8	$1.6	$0.0	$143.4	$149.2	($7.1)	($0.0)	$142.1
Aug	$96.1	$2.4	$0.0	$98.5	$91.3	($7.7)	($0.0)	$83.6
Sep	$71.7	($0.9)	($0.0)	$70.8	$85.0	($8.2)	($0.0)	$76.8
Total	$776.0	($18.5)	$0.0	$757.6	$871.5	($74.6)	($0.0)	$796.9

Figure 11-2 shows PJM monthly marginal loss costs of January 2009 through September 2013.

Figure 11-2 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through September of 2013



Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (generation energy credits less load energy payments) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to load and exports as marginal loss credits.

Table 11-14 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for the first nine months of 2009 through 2013. The total marginal loss credits decreased $46.0 million in the first nine months of 2013 from the first nine months of 2012.

Table 11-14 Marginal loss credits (Dollars (Millions)): January through September, 2009 through 2013[14]

	Loss Credit Accounting (Millions)			
(Jan-Sep)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($484.6)	$992.4	$0.7	$508.5
2010	($618.6)	$1,259.3	($1.2)	$639.6
2011	($651.3)	$1,152.6	$0.7	$502.1
2012	($442.6)	$757.6	($1.7)	$313.3
2013	($527.6)	$796.9	($2.1)	$267.3

Congestion

Congestion Accounting

Total congestion costs in PJM in the first nine months of 2013 were $508.7 million, which was comprised of load congestion payments of $233.1 million, generation credits of -$340.5 million and explicit congestion of -$64.8 million (Table 11-16).

14 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Total Congestion

Table 11-15 shows total congestion from January through September by year from 2008 through 2013.[15]

Table 11-15 Total PJM congestion (Dollars (Millions)): January through September, 2008 to 2013

	Congestion Costs (Millions)			
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778.2	NA	$26,979	6.6%
2009	$543.6	(69.4%)	$19,927	2.7%
2010	$1,134.3	108.7%	$26,249	4.3%
2011	$874.9	(22.9%)	$28,836	3.0%
2012	$425.2	(51.4%)	$22,119	1.9%
2013	$508.7	19.6%	$25,153	2.0%

Total congestion costs in Table 11-16 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[16,17]

Table 11-16 shows the congestion costs by category for the first nine months of 2013. The January through September 2013 PJM total congestion costs were comprised of $233.1 million in load congestion payments, -$340.5 million in generation congestion credits, and -$64.8 million in explicit congestion costs.

Table 11-16 Total PJM congestion costs by category (Dollars (Millions)): January through September, 2008 to 2013

	Congestion Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$921.9	($880.7)	($24.5)	$0.0	$1,778.2
2009	$210.6	($380.9)	($48.0)	$0.0	$543.6
2010	$290.2	($893.3)	($49.2)	($0.0)	$1,134.3
2011	$442.0	($535.7)	($102.8)	$0.0	$874.9
2012	$103.3	($372.7)	($50.9)	$0.0	$425.2
2013	$233.1	($340.5)	($64.8)	$0.0	$508.7

15 Congestion charges for 2010 reflect an updated calculation compared to the results in the *2010 State of the Market Report for PJM.*
16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) Section 6.1 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed April 17, 2013).
17 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.2.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Table 11-17 Total PJM congestion costs by market category (Dollars (Millions)): January through September, 2008 to 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$0.0	$1,778.2
2009	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$0.0	$543.6
2010	$301.7	($932.7)	$69.5	$1,303.9	($11.5)	$39.3	($118.7)	($169.6)	($0.0)	$1,134.3
2011	$389.3	($628.2)	$45.6	$1,063.2	$52.7	$92.6	($148.4)	($188.3)	$0.0	$874.9
2012	$106.6	($409.8)	$86.7	$603.2	($3.3)	$37.1	($137.6)	($178.0)	$0.0	$425.2
2013	$226.3	($452.6)	$121.6	$800.5	$6.8	$112.2	($186.4)	($291.8)	$0.0	$508.7

Monthly Congestion

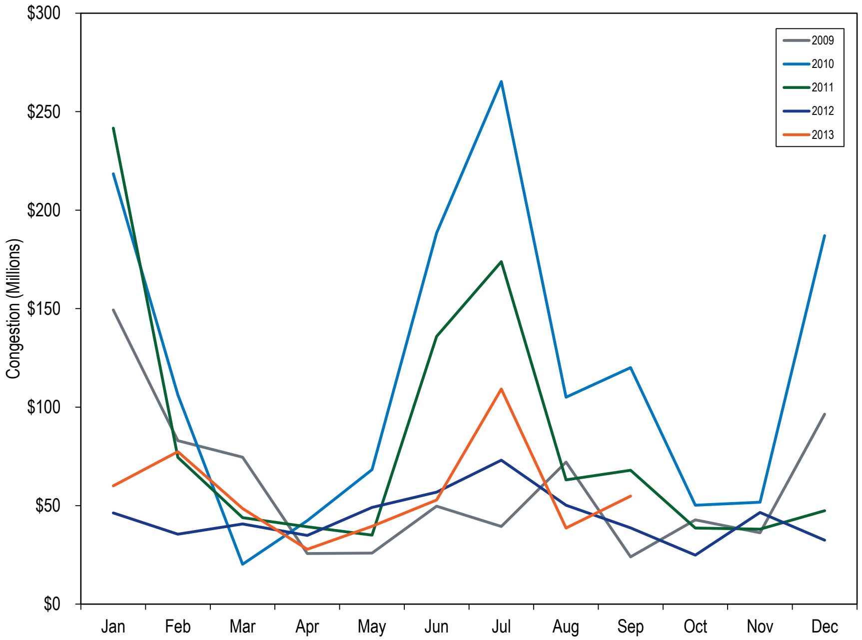
Table 11-18 shows that during the first nine months of 2012 and 2013, monthly total congestion costs ranged from $27.8 million to $109.2 million in 2013. Table 11-18 shows the monthly congestion costs in the first nine months of 2013 were higher than in the first nine months of 2012.

Table 11-18 Monthly PJM congestion costs by market type (Dollars (Millions)): January through September, 2012 to 2013

	Congestion Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$66.3	($20.0)	$0.0	$46.3	$136.8	($76.8)	$0.0	$60.0
Feb	$54.8	($19.2)	$0.0	$35.5	$125.1	($47.7)	$0.0	$77.4
Mar	$59.8	($19.2)	$0.0	$40.6	$69.9	($21.4)	($0.0)	$48.5
Apr	$72.0	($37.1)	$0.0	$34.9	$37.7	($9.9)	$0.0	$27.8
May	$67.2	($18.2)	($0.0)	$49.1	$75.3	($35.8)	($0.0)	$39.5
Jun	$69.6	($12.7)	($0.0)	$56.8	$82.2	($29.4)	($0.0)	$52.8
Jul	$91.0	($17.9)	$0.0	$73.1	$130.5	($21.3)	$0.0	$109.2
Aug	$60.8	($10.6)	$0.0	$50.2	$46.0	($7.4)	$0.0	$38.6
Sep	$61.8	($23.1)	($0.0)	$38.7	$97.0	($42.1)	$0.0	$54.9
Total	$603.2	($178.0)	$0.0	$425.2	$800.5	($291.8)	$0.0	$508.7

Figure 11-3 shows PJM monthly total congestion cost for January 2009 through September 2013.

Figure 11-3 PJM monthly total congestion cost (Dollars (Millions)): January 2009 to September 2013



Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours likely exceeds the number of constrained hours and the number of congestion-event hours likely exceeds the number of hours within a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In the first nine months of 2013, there were 259,605 day-ahead, congestion-event hours compared to 168,509 day-ahead, congestion-event hours in the first nine months of 2012. In the first nine months of 2013, there were 14,249 real-time, congestion-event hours compared to 15,153 real-time, congestion-event hours in the first nine months of 2012.

During the first nine months of 2013, for only 2.0 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During the first nine months of 2013, for 37.9 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The AP South Interface was the largest contributor to congestion costs in the first nine months of 2013. With $144.1 million in total congestion costs, it accounted for 28.3 percent of the total PJM congestion costs in the first nine months of 2013. The top five constraints in terms of congestion costs together contributed $183.8 million, or 36.1 percent, of the total PJM congestion costs in the first nine months of 2013. The top five constraints were the AP South interface, the West interface, the ATSI interface, and the Bridgewater – Middlesex line, and the Cloverdale transformer.

Congestion by Facility Type and Voltage

In the first nine months of 2013, compared to the first nine months of 2012, day-ahead, congestion-event hours increased on all types of facilities. Real-time, congestion-event hours decreased on all types of facilities except internal PJM interfaces.

Day-ahead congestion costs decreased on the flowgates in the first nine months of 2013 compared to the first nine months of 2012 and increased on PJM interfaces, transmission lines and transformers in the first nine months of 2013 compared to the first nine months of 2012. Balancing congestion costs increased on flowgates and decreased on transformers, transmission lines and interfaces in the first nine months of 2013 compared to the first nine months of 2012.

Table 11-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the first nine months of 2013 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[18,19] For comparison, this information is presented in Table 11-20 for the first nine months of 2012.[20]

Table 11-21 and Table 11-22 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Market, the number of hours during which the facility is also constrained in the Real-Time Market are presented in Table 11-21. In the first nine months of 2013, there were 259,605 congestion event hours in the Day-Ahead Market. Among those, only 5,244 (2.0 percent) were also constrained in the Real-Time Market. In the first nine months of 2012, among the 168,509 day-ahead congestion event hours, only 6,238 (3.7 percent) were binding in the Real-Time Market.[21]

Among the hours for which a facility is constrained in the Real-Time Market, the number of hours during which the facility is also constrained in the Day-Ahead Market are presented in Table 11-22. In the first nine months of 2013, there were 14,249 congestion event hours in the Real-Time Market. Among these, 5,395 (37.9 percent) were also constrained in the Day-Ahead Market. In the first nine months of 2012, among the 15,153 real-time congestion event hours, only 6,123 (40.4 percent) were binding in the Day-Ahead Market.

Table 11-19 Congestion summary (By facility type): January through September 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	RealTime
Flowgate	($32.6)	($131.1)	$18.7	$117.2	$0.4	$11.8	($36.0)	($47.4)	$69.8	22,653	4,320
Interface	$141.3	($77.8)	$15.1	$234.2	$22.3	$29.1	($35.2)	($42.0)	$192.2	10,748	1,229
Line	$62.4	($204.5)	$54.0	$320.9	($17.5)	$59.4	($93.7)	($170.6)	$150.3	144,886	7,278
Other	$7.2	($2.4)	$6.4	$16.0	($0.4)	$0.1	($3.0)	($3.5)	$12.5	8,880	120
Transformer	$22.2	($56.0)	$21.2	$99.4	$1.6	$9.6	($19.8)	($27.8)	$71.6	72,438	1,302
Unclassified	$25.9	$19.2	$6.2	$12.8	$0.4	$2.1	$1.3	($0.4)	$12.4	NA	NA
Total	$226.3	($452.6)	$121.6	$800.5	$6.8	$112.2	($186.4)	($291.8)	$508.7	259,605	14,249

18 Unclassified are congestion costs related to non-transmission facility constraints in the Day-Ahead Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Non-transmission facility constraints include Day-Ahead Market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

19 The term flowgate refers to MISO flowgates and NYISO flowgates in this section.

20 For 2008 and 2009, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs.

21 Constraints are mapped to transmission facilities. In the Day-Ahead Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Table 11-20 Congestion summary (By facility type): January through September 2012

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($42.4)	($144.3)	$28.4	$130.4	($4.4)	$7.5	($66.6)	($78.5)	$51.9	21,675	5,319
Interface	$48.5	($51.1)	$0.0	$99.6	$12.8	$15.5	($3.3)	($6.1)	$93.6	4,460	421
Line	$65.6	($157.1)	$41.0	$263.7	($8.4)	$18.2	($54.9)	($81.5)	$182.2	101,732	7,708
Other	$9.5	($3.9)	$1.4	$14.8	($0.6)	$0.0	($0.9)	($1.6)	$13.2	5,087	428
Transformer	$29.2	($45.4)	$14.3	$88.9	$4.1	$2.7	($11.6)	($10.1)	$78.8	35,555	1,277
Unclassified	$2.8	($1.4)	$1.6	$5.8	$0.2	$0.2	($0.2)	($0.3)	$5.5	NA	NA
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$425.2	168,509	15,153

Table 11-21 Congestion Event Hours (Day Ahead against Real Time): January through September 2012 to 2013

	Congestion Event Hours					
	2012 (Jan - Sep)			2013 (Jan - Sep)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	21,675	2,510	11.6%	22,653	1,603	7.1%
Interface	4,460	167	3.7%	10,748	870	8.1%
Line	101,732	2,731	2.7%	144,886	2,217	1.5%
Other	5,087	265	5.2%	8,880	161	1.8%
Transformer	35,555	565	1.6%	72,438	393	0.5%
Total	168,509	6,238	3.7%	259,605	5,244	2.0%

Table 11-22 Congestion Event Hours (Real Time against Day Ahead): January through September 2012 to 2013

	Congestion Event Hours					
	2012 (Jan - Sep)			2013 (Jan - Sep)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	5,319	2,586	48.6%	4,320	1,739	40.3%
Interface	421	165	39.2%	1,229	952	77.5%
Line	7,708	2,603	33.8%	7,278	2,219	30.5%
Other	428	229	53.5%	120	99	82.5%
Transformer	1,277	540	42.3%	1,302	386	29.6%
Total	15,153	6,123	40.4%	14,249	5,395	37.9%

Table 11-23 shows congestion costs by facility voltage class for the first nine months of 2013. In comparison to the first nine months of 2012 (shown in Table 11-24), congestion costs decreased for facilities rated at 345 kV, 138 kV, and 115 kV in the first nine months of 2013.

Table 11-23 Congestion summary (By facility voltage): January through September 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$4.5	($15.7)	$7.6	$27.9	($0.2)	$0.5	$0.8	$0.1	$28.0	7,783	15
500	$141.6	($89.8)	$17.9	$249.2	$27.8	$34.0	($47.1)	($53.2)	$196.0	14,345	1,630
345	($32.4)	($128.2)	$16.1	$111.9	($0.9)	$14.2	($45.4)	($60.5)	$51.4	45,323	3,069
230	$64.4	($113.9)	$38.3	$216.5	($4.5)	$45.5	($48.2)	($98.2)	$118.4	42,397	2,639
161	($4.5)	($9.1)	($0.9)	$3.7	($1.1)	$0.4	($3.0)	($4.5)	($0.8)	1,036	682
138	($13.4)	($119.6)	$33.4	$139.6	($6.2)	$12.4	($41.5)	($60.0)	$79.6	114,898	4,698
123	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
115	$13.3	($0.1)	$3.1	$16.5	($2.9)	($0.7)	($4.0)	($6.2)	$10.3	13,597	908
69	$21.5	$2.4	($0.9)	$18.2	($5.8)	$3.7	$0.7	($8.8)	$9.4	13,661	579
34	($0.0)	($0.1)	$0.1	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	6,007	29
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	32	0
Unclassified	$25.9	$19.2	$6.2	$12.8	$0.4	$2.1	$1.3	($0.4)	$12.4	NA	NA
Total	$226.3	($452.6)	$121.6	$800.5	$6.8	$112.2	($186.4)	($291.8)	$508.7	259,605	14,249

Table 11-24 Congestion summary (By facility voltage): January through September 2012

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	($0.1)	($2.8)	$2.6	$5.3	$0.2	($0.1)	($0.1)	$0.1	$5.4	2,256	89
500	$51.6	($59.8)	$1.9	$113.3	$14.1	$15.2	($5.8)	($6.9)	$106.4	7,757	648
345	($33.5)	($103.2)	$14.1	$83.7	$1.0	$6.1	($30.1)	($35.2)	$48.6	22,950	2,254
230	$62.8	($61.0)	$12.4	$136.2	$5.6	$5.9	($22.0)	($22.2)	$113.9	25,427	3,280
161	($11.4)	($17.9)	$4.5	$11.1	($0.8)	$1.5	($9.7)	($11.9)	($0.8)	3,021	1,189
138	($2.2)	($159.5)	$46.6	$203.8	($6.8)	$11.5	($69.1)	($87.3)	$116.5	86,601	6,177
115	$21.1	($2.2)	$2.6	$25.9	($0.4)	$1.5	($1.1)	($3.0)	$22.9	13,155	738
69	$22.0	$4.5	$0.6	$18.2	($9.5)	$2.3	$0.5	($11.3)	$6.8	7,330	776
34	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	0	2
12	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	12	0
Unclassified	$2.8	($1.4)	$1.6	$5.8	$0.2	$0.2	($0.2)	($0.3)	$5.5	NA	NA
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$425.2	168,509	15,153

Constraint Duration

Table 11-25 lists constraints in the first nine months of 2012 and 2013 that were most frequently in effect and Table 11-26 shows the constraints which experienced the largest change in congestion-event hours from the first nine month of 2012 to the first nine months of 2013.

Table 11-25 Top 25 constraints with frequent occurrence: January through September 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Sporn	Transformer	11,194	7,742	(3,452)	0	0	0	128%	88%	(40%)	0%	0%	0%
2	Gould Street - Westport	Line	0	6,007	6,007	2	21	19	0%	68%	68%	0%	0%	0%
3	Braidwood	Transformer	0	5,710	5,710	0	0	0	0%	65%	65%	0%	0%	0%
4	AP South	Interface	1,725	4,757	3,032	157	915	758	20%	54%	34%	2%	10%	9%
5	Sunbury	Transformer	0	4,915	4,915	0	0	0	0%	56%	56%	0%	0%	0%
6	Tanners Creek	Transformer	460	4,901	4,441	0	0	0	5%	56%	51%	0%	0%	0%
7	Howard - Shelby	Line	1,992	4,415	2,423	0	0	0	23%	50%	28%	0%	0%	0%
8	Nelson - Cordova	Line	1,587	3,919	2,332	253	238	(15)	18%	45%	26%	3%	3%	(0%)
9	Readington - Roseland	Line	340	3,206	2,866	20	713	693	4%	36%	33%	0%	8%	8%
10	Haurd - Steward	Line	1,213	3,366	2,153	1	0	(1)	14%	38%	24%	0%	0%	(0%)
11	West Moulton-City Of St. Marys	Line	0	3,315	3,315	0	0	0	0%	38%	38%	0%	0%	0%
12	Rockport Works	Transformer	0	2,844	2,844	0	0	0	0%	32%	32%	0%	0%	0%
13	Bridgewater - Middlesex	Line	237	2,395	2,158	1	230	229	3%	27%	25%	0%	3%	3%
14	Zion	Line	211	2,565	2,354	0	0	0	2%	29%	27%	0%	0%	0%
15	Monticello - East Winamac	Flowgate	2,556	1,926	(630)	567	542	(25)	29%	22%	(7%)	6%	6%	(0%)
16	South Cadiz	Transformer	842	2,455	1,613	0	0	0	10%	28%	18%	0%	0%	0%
17	Cloverdale	Transformer	133	2,409	2,276	20	0	(20)	2%	27%	26%	0%	0%	(0%)
18	Mardela - Vienna	Line	206	2,142	1,936	126	199	73	2%	24%	22%	1%	2%	1%
19	Michigan City - Laporte	Flowgate	873	2,304	1,431	40	0	(40)	10%	26%	16%	0%	0%	(0%)
20	Danville - East Danville	Line	1,573	2,267	694	6	3	(3)	18%	26%	8%	0%	0%	(0%)
21	Clinch River	Transformer	0	2,236	2,236	0	0	0	0%	25%	25%	0%	0%	0%
22	Hunlock Creek - A.G.A. Gas	Line	15	2,215	2,200	0	0	0	0%	25%	25%	0%	0%	0%
23	Halifax - Halifax 115	Line	1,195	2,213	1,018	0	0	0	14%	25%	12%	0%	0%	0%
24	Huntingdon - Huntingdon1	Line	2,786	2,202	(584)	0	0	0	32%	25%	(7%)	0%	0%	0%
25	Beckjord	Transformer	0	2,184	2,184	0	0	0	0%	25%	25%	0%	0%	0%

Table 11-26 Top 25 constraints with largest year-to-year change in occurrence: January through September 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Gould Street - Westport	Line	0	6,007	6,007	2	21	19	0%	68%	68%	0%	0%	0%
2	Braidwood	Transformer	0	5,710	5,710	0	0	0	0%	65%	65%	0%	0%	0%
3	Sunbury	Transformer	0	4,915	4,915	0	0	0	0%	56%	56%	0%	0%	0%
4	Tanners Creek	Transformer	460	4,901	4,441	0	0	0	5%	56%	51%	0%	0%	0%
5	AP South	Interface	1,725	4,757	3,032	157	915	758	20%	54%	34%	2%	10%	9%
6	Readington - Roseland	Line	340	3,206	2,866	20	713	693	4%	36%	33%	0%	8%	8%
7	Sporn	Transformer	11,194	7,742	(3,452)	0	0	0	128%	88%	(40%)	0%	0%	0%
8	West Moulton-City Of St. Marys	Line	0	3,315	3,315	0	0	0	0%	38%	38%	0%	0%	0%
9	Graceton - Raphael Road	Line	2,494	0	(2,494)	697	0	(697)	28%	0%	(28%)	8%	0%	(8%)
10	Rockport Works	Transformer	0	2,844	2,844	0	0	0	0%	32%	32%	0%	0%	0%
11	Oak Grove - Galesburg	Flowgate	3,021	1,009	(2,012)	1,182	594	(588)	34%	11%	(23%)	13%	7%	(7%)
12	Howard - Shelby	Line	1,992	4,415	2,423	0	0	0	23%	50%	28%	0%	0%	0%
13	Bridgewater - Middlesex	Line	237	2,395	2,158	1	230	229	3%	27%	25%	0%	3%	3%
14	Zion	Line	211	2,565	2,354	0	0	0	2%	29%	27%	0%	0%	0%
15	Nelson - Cordova	Line	1,587	3,919	2,332	253	238	(15)	18%	45%	26%	3%	3%	(0%)
16	Cloverdale	Transformer	133	2,409	2,276	20	0	(20)	2%	27%	26%	0%	0%	(0%)
17	Clinch River	Transformer	0	2,236	2,236	0	0	0	0%	25%	25%	0%	0%	0%
18	Hunlock Creek - A.G.A. Gas	Line	15	2,215	2,200	0	0	0	0%	25%	25%	0%	0%	0%
19	Beckjord	Transformer	0	2,184	2,184	0	0	0	0%	25%	25%	0%	0%	0%
20	Haurd - Steward	Line	1,213	3,366	2,153	1	0	(1)	14%	38%	24%	0%	0%	(0%)
21	Mardela - Vienna	Line	206	2,142	1,936	126	199	73	2%	24%	22%	1%	2%	1%
22	Clover	Transformer	1,564	30	(1,534)	441	36	(405)	18%	0%	(18%)	5%	0%	(5%)
23	Electric Junction - Frontenac	Line	0	1,901	1,901	0	0	0	0%	22%	22%	0%	0%	0%
24	Westvaco - Cross School	Line	87	1,957	1,870	0	0	0	1%	22%	21%	0%	0%	0%
25	Loretto	Transformer	170	2,030	1,860	0	0	0	2%	23%	21%	0%	0%	0%

Constraint Costs

Table 11-27 and Table 11-28 present the top constraints affecting congestion costs by facility for the periods January through September 2013 and 2012.

Table 11-27 Top 25 constraints affecting PJM congestion costs (By facility): January through September 2013

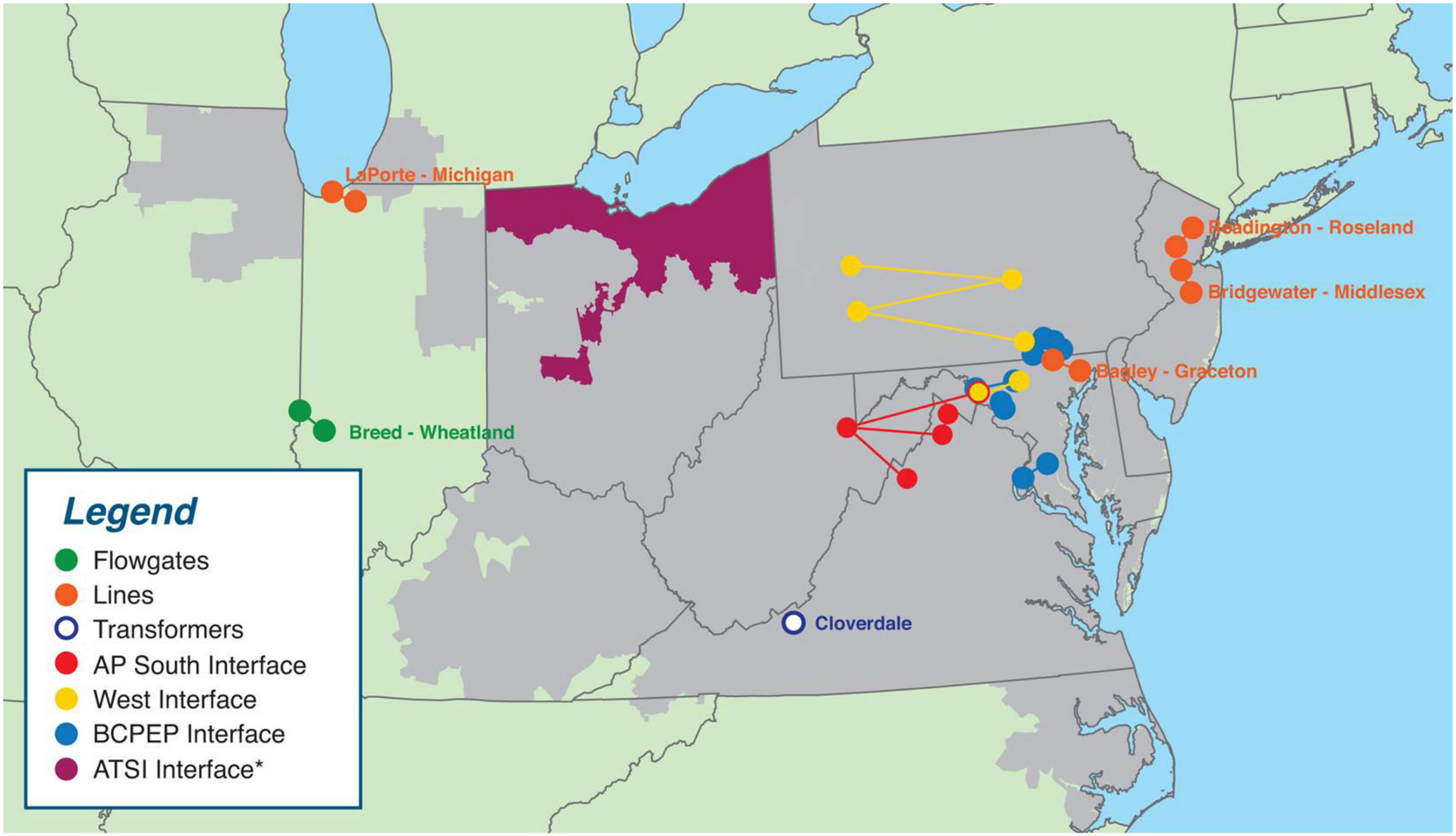
				Congestion Costs (Millions)								Percent of Total PJM Congestion Costs	
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2013 (Jan - Sep)
1	AP South	Interface	500	$116.8	($29.5)	$12.9	$159.2	$7.5	$13.3	($9.2)	($15.1)	$144.1	28.3%
2	West	Interface	500	$3.2	($24.1)	$0.1	$27.4	$2.9	$3.1	($1.1)	($1.2)	$26.2	5.2%
3	ATSI	Interface	ATSI	$0.0	$0.0	$0.0	$0.0	$10.2	$9.0	($24.7)	($23.5)	($23.5)	(4.6%)
4	Bridgewater - Middlesex	Line	PSEG	($0.1)	($23.0)	$1.9	$24.8	$1.8	$4.5	($1.8)	($4.4)	$20.4	4.0%
5	Cloverdale	Transformer	AEP	$8.0	($3.6)	$4.9	$16.5	$0.0	$0.0	$0.0	$0.0	$16.5	3.3%
6	Readington - Roseland	Line	PSEG	($1.8)	($49.5)	$5.2	$52.9	($10.5)	$38.1	($20.7)	($69.3)	($16.3)	(3.2%)
7	BCPEP	Interface	Pepco	$11.8	($1.8)	$1.9	$15.6	$0.0	$0.0	$0.0	$0.0	$15.6	3.1%
8	Breed - Wheatland	Flowgate	MISO	($2.8)	($16.0)	$1.8	$15.0	$0.1	($0.1)	($1.3)	($1.1)	$13.9	2.7%
9	Bagley - Graceton	Line	BGE	$11.1	($0.7)	$1.8	$13.7	$0.3	($1.0)	($1.9)	($0.6)	$13.1	2.6%
10	Laporte - Michigan City	Line	AEP	$0.0	$0.0	$0.0	$0.0	($6.7)	$1.3	($4.9)	($12.9)	($12.9)	(2.5%)
11	Unclassified	Unclassified	Unclassified	$25.9	$19.2	$6.2	$12.8	$0.4	$2.1	$1.3	($0.4)	$12.4	2.4%
12	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.2)	$5.1	($6.8)	($12.1)	($12.1)	(2.4%)
13	Monticello - East Winamac	Flowgate	MISO	($2.3)	($26.8)	$4.0	$28.5	$0.2	$5.4	($11.3)	($16.5)	$12.0	2.4%
14	Byron - Cherry Valley	Flowgate	MISO	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	2.0%
15	5004/5005 Interface	Interface	500	$0.8	($11.7)	($0.4)	$12.2	$1.4	$3.9	$0.3	($2.2)	$10.0	2.0%
16	Bedington - Black Oak	Interface	500	$6.1	($3.1)	$0.8	$9.9	$0.1	($0.0)	($0.3)	($0.2)	$9.7	1.9%
17	Crete - St Johns Tap	Flowgate	MISO	($0.5)	($7.1)	$2.7	$9.3	$0.0	$0.0	$0.0	$0.0	$9.3	1.8%
18	South Canton	Transformer	AEP	($3.3)	($11.1)	$1.1	$8.9	($0.2)	$0.5	$0.8	$0.1	$8.9	1.8%
19	Conastone - Graceton	Line	BGE	$5.4	($2.0)	$1.6	$9.0	($0.0)	($0.1)	($0.2)	($0.2)	$8.8	1.7%
20	Byron - Cherry Valley	Line	ComEd	($0.0)	($0.1)	$0.0	$0.1	($1.2)	$2.5	($5.0)	($8.7)	($8.6)	(1.7%)
21	Bedington	Transformer	AP	$3.5	($5.1)	($0.0)	$8.6	$0.0	$0.4	$0.3	($0.1)	$8.5	1.7%
22	Braidwood	Transformer	ComEd	($0.2)	($7.4)	$1.2	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	1.7%
23	Michigan City - Laporte	Flowgate	MISO	($5.9)	($10.6)	$2.5	$7.2	$0.0	$0.0	$0.0	$0.0	$7.2	1.4%
24	New Dover - Westfield	Line	PSEG	$0.5	($5.8)	$0.9	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	1.4%
25	AEP - DOM	Interface	500	$4.0	($2.5)	$0.3	$6.8	($0.1)	$0.1	($0.0)	($0.2)	$6.6	1.3%

Table 11-28 Top 25 constraints affecting PJM congestion costs (By facility): January through September 2012

				Congestion Costs (Millions)								Percent of Total PJM Congestion Costs	
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2012 (Jan - Sep)
1	AP South	Interface	500	$36.0	($14.0)	$1.3	$51.3	$7.1	$4.6	($2.9)	($0.4)	$50.9	12.0%
2	Graceton - Raphael Road	Line	BGE	$25.1	($7.8)	($1.6)	$31.3	$0.8	($1.1)	$0.2	$2.1	$33.4	7.9%
3	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	7.0%
4	Belvidere - Woodstock	Line	ComEd	($0.2)	($4.7)	$0.9	$5.4	($2.4)	$3.2	($16.8)	($22.5)	($17.1)	(4.0%)
5	Clover	Transformer	Dominion	$9.4	($7.5)	$6.7	$23.6	$0.9	$0.7	($8.4)	($8.2)	$15.3	3.6%
6	West	Interface	500	($0.6)	($17.4)	($2.2)	$14.5	$1.2	$1.2	$0.5	$0.4	$15.0	3.5%
7	Monticello - East Winamac	Flowgate	MISO	($0.2)	($18.9)	$11.1	$29.8	$0.4	$2.0	($15.4)	($16.9)	$12.9	3.0%
8	Bedington - Black Oak	Interface	500	$9.0	($4.0)	($0.0)	$13.0	$1.0	$1.1	($0.7)	($0.8)	$12.1	2.9%
9	Loudoun - Gainsville	Line	Dominion	$0.4	($11.0)	($1.2)	$10.2	$0.6	$0.9	$0.2	($0.1)	$10.0	2.4%
10	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	2.1%
11	Nelson - Cordova	Line	ComEd	($16.6)	($29.5)	$5.8	$18.7	($0.9)	$1.6	($7.5)	($10.0)	$8.7	2.0%
12	Hunterstown	Transformer	Met-Ed	$3.4	($4.2)	$0.2	$7.8	$0.1	$0.0	($0.0)	$0.0	$7.8	1.8%
13	Pleasant Valley - Belvidere	Line	ComEd	($2.2)	($8.0)	$1.8	$7.6	$0.1	$0.1	($0.8)	($0.7)	$6.9	1.6%
14	Kammer	Transformer	AEP	($3.0)	($11.2)	($1.3)	$6.9	($0.2)	$0.1	$0.2	($0.0)	$6.9	1.6%
15	Unclassified	Unclassified	Unclassified	$2.8	($1.4)	$1.6	$5.8	$0.2	$0.2	($0.2)	($0.3)	$5.5	1.3%
16	AEP - DOM	Interface	500	$6.0	($2.1)	$0.9	$9.0	$1.0	$4.2	($0.5)	($3.7)	$5.3	1.2%
17	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.2	($0.1)	$0.0	$5.1	1.2%
18	Belmont	Transformer	AP	$0.6	($5.5)	$0.6	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	1.2%
19	Plymouth Meeting - Whitpain	Line	PECO	$0.8	($3.9)	($0.1)	$4.6	$0.3	$0.7	$0.5	$0.0	$4.7	1.1%
20	Electric Junction - Nelson	Line	ComEd	($1.3)	($4.2)	$1.7	$4.6	$0.0	$0.0	($0.0)	($0.0)	$4.6	1.1%
21	Silver Lake - Pleasant Valley	Line	ComEd	($2.8)	($6.0)	$1.3	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	1.1%
22	Buxmont - Whitpain	Line	PECO	($1.1)	($7.0)	($1.5)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	1.0%
23	East	Interface	500	($2.6)	($7.9)	($0.6)	$4.7	$0.1	$0.5	($0.1)	($0.5)	$4.2	1.0%
24	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$2.4	$3.2	$0.5	($0.4)	$4.2	1.0%
25	Kenova - Tri State	Line	AEP	$0.4	($3.4)	($0.1)	$3.8	($0.0)	$0.1	$0.1	$0.0	$3.8	0.9%

Figure 11-4 shows the locations of the top 10 constraints affecting PJM congestion costs in the first nine months of 2013.

Figure 11-4 Location of the top 10 constraints affecting PJM congestion costs: January through September 2013[22]



* ATSI is comprised of all tie lines into the ATSI transmission zone.

22 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates in this section.

Congestion-Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[23] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.24 PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 11-29 and Table 11-30 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first nine months of 2013 and 2012, and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first nine months of 2013, the Breed - Wheatland flowgate made the most significant contribution to positive congestion while the Beaver Channel - Albany flowgate made the most significant contribution to negative congestion.

Table 11-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September 2013

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Breed - Wheatland	($2.8)	($16.0)	$1.8	$15.0	$0.1	($0.1)	($1.3)	($1.1)	$13.9	1,714	293
2	Monticello - East Winamac	($2.3)	($26.8)	$4.0	$28.5	$0.2	$5.4	($11.3)	($16.5)	$12.0	1,926	542
3	Byron - Cherry Valle	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	72	0
4	Crete - St Johns Tap	($0.5)	($7.1)	$2.7	$9.3	$0.0	$0.0	$0.0	$0.0	$9.3	1,165	0
5	Michigan City - Laporte	($5.9)	($10.6)	$2.5	$7.2	$0.0	$0.0	$0.0	$0.0	$7.2	2,304	0
6	Benton Harbor - Palisades	($1.4)	($7.5)	$2.5	$8.6	($0.1)	$0.8	($2.0)	($2.8)	$5.8	1,700	114
7	Rocky - Battlebo	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
8	Rantoul - Rantoul Jct	($3.7)	($5.8)	$1.6	$3.8	$0.0	$0.0	$0.0	$0.0	$3.8	1,673	0
9	Edwards - Kewanee	($2.5)	($4.1)	$2.0	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,095	12
10	Prairie State - W Mt. Vernon	($2.0)	($5.2)	($0.4)	$2.8	($0.0)	($0.1)	$0.7	$0.8	$3.6	1,021	836
11	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.1	($2.6)	($3.4)	($3.4)	0	83
12	Miami Fort	($0.9)	($3.7)	($0.0)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1,098	0
13	Oak Grove - Galesburg	($0.8)	($2.7)	$0.9	$2.8	($0.0)	($0.0)	($0.5)	($0.5)	$2.3	1,278	76
14	Volunteer - Phiipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
15	Stillwell	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($1.4)	($1.9)	($1.9)	0	64
16	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.5)	$0.7	($0.5)	($1.7)	($1.7)	0	193
17	Hennepin	($0.2)	($0.5)	($0.1)	$0.1	($0.2)	$0.0	($1.4)	($1.6)	($1.5)	82	161
18	Pleasant Prairie - Zion	($0.5)	($1.6)	$0.7	$1.8	($0.0)	($0.0)	($0.5)	($0.5)	$1.3	855	76
19	Miami Fort - Hebron	($0.3)	($1.1)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	423	0
20	Roxana - Praxair	($2.3)	($2.6)	$0.4	$0.7	$0.3	$0.4	($1.4)	($1.4)	($0.7)	648	92

23 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

24 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 2.2.24 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

Table 11-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September 2012

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Woodstock	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	1,073	0
2	Monticello - East Winamac	($0.2)	($18.9)	$11.1	$29.8	$0.4	$2.0	($15.4)	($16.9)	$12.9	2,556	567
3	Palisades - Roosevelt	($0.8)	($5.1)	($0.6)	$3.7	$0.1	$0.3	($0.2)	($0.4)	$3.3	747	209
4	Crete - St Johns Tap	($4.9)	($15.5)	($1.3)	$9.3	$0.3	$0.9	($5.7)	($6.3)	$3.0	1,916	277
5	Breed - Wheatland	($1.3)	($8.2)	($0.1)	$6.9	$0.3	$0.3	($9.6)	($9.6)	($2.8)	1,269	276
6	Miami Fort - Hebron	($1.4)	($4.2)	($0.2)	$2.6	($0.1)	($0.0)	$0.1	$0.0	$2.6	690	76
7	Benton Harbor - Palisades	($0.4)	($3.5)	($0.8)	$2.4	$0.1	$0.3	($0.2)	($0.4)	$2.0	512	71
8	Rising	($0.3)	($0.3)	$0.0	$0.1	($0.4)	$0.2	($1.1)	($1.6)	($1.5)	48	114
9	Prairie State - W Mt. Vernon	($1.8)	($2.8)	$0.5	$1.5	($0.0)	$0.0	($0.2)	($0.2)	$1.3	511	190
10	Cumberland - Bush	($1.2)	($5.5)	$6.2	$10.5	$0.4	$1.2	($10.9)	($11.7)	($1.2)	2,053	313
11	Edwards - Kewanee	($0.2)	($0.9)	$0.5	$1.1	$0.0	($0.1)	($0.2)	($0.1)	$1.0	224	59
12	Rantoul - Rantoul Jct	($2.3)	($4.8)	$0.3	$2.8	($0.2)	($0.1)	($1.7)	($1.9)	$0.9	1,075	315
13	Oak Grove - Galesburg	($11.4)	($17.9)	$4.5	$11.1	($0.8)	$1.5	($9.6)	($11.8)	($0.7)	3,021	1,182
14	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.7)	($0.7)	0	12
15	Bunsonville - Eugene	($0.7)	($1.1)	$0.2	$0.7	$0.0	($0.1)	($0.1)	($0.0)	$0.7	236	42
16	Dunes Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	180	11
17	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.6)	($0.7)	($0.7)	0	23
18	Michigan City - Laporte	($0.8)	($2.3)	($0.3)	$1.1	($0.3)	($0.1)	($0.3)	($0.5)	$0.6	873	40
19	Brokaw - Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	0
20	Sheffield - Marktown	($1.1)	($2.1)	$0.2	$1.2	$0.2	$0.5	($0.3)	($0.7)	$0.5	1,055	10

Congestion-Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.[25] Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M Flowgates. Flowgates eligible for the M2M coordination process are called M2M Flowgates.[26]

25 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.3.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).
26 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.23 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Table 11-31 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first nine months of 2013, and which had the greatest congestion cost impact on PJM.

Table 11-31 Top congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through September 2013

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central east	Flowgate	NYISO	$0.3	($1.2)	($0.2)	$1.3	$0.6	$2.1	($1.4)	($2.9)	($1.6)	48	167
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.2)	($0.2)	0	21

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-32 and Table 11-33 show the 500 kV constraints impacting congestion costs in PJM for the first nine months of 2013 and 2012. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 11-32 Regional constraints summary (By facility): January through September 2013

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$116.8	($29.5)	$12.9	$159.2	$7.5	$13.3	($9.2)	($15.1)	$144.1	4,757	915
2	West	Interface	500	$3.2	($24.1)	$0.1	$27.4	$2.9	$3.1	($1.1)	($1.2)	$26.2	1,387	79
3	5004/5005 Interface	Interface	500	$0.8	($11.7)	($0.4)	$12.2	$1.4	$3.9	$0.3	($2.2)	$10.0	505	150
4	Bedington - Black Oak	Interface	500	$6.1	($3.1)	$0.8	$9.9	$0.1	($0.0)	($0.3)	($0.2)	$9.7	1,172	16
5	AEP - DOM	Interface	500	$4.0	($2.5)	$0.3	$6.8	($0.1)	$0.1	($0.0)	($0.2)	$6.6	1,317	10
6	Conemaugh - Hunterstown	Line	500	$0.4	($2.6)	$0.3	$3.4	$0.5	$0.7	($0.7)	($0.9)	$2.5	153	68
7	Central	Interface	500	($0.9)	($3.3)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	167	0
8	East	Interface	500	($0.5)	($1.7)	($0.0)	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	254	0
9	Juniata	Transformer	500	$0.2	($0.3)	$0.2	$0.7	$0.4	$0.1	($0.4)	($0.1)	$0.6	0	4
10	Nagel - Phipps Bend	Line	500	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
11	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	0	6
12	EAST	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	4

Table 11-33 Regional constraints summary (By facility): January through September 2012

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$36.0	($14.0)	$1.3	$51.3	$7.1	$4.6	($2.9)	($0.4)	$50.9	1,725	157
2	West	Interface	500	($0.6)	($17.4)	($2.2)	$14.5	$1.2	$1.2	$0.5	$0.4	$15.0	369	17
3	Bedington - Black Oak	Interface	500	$9.0	($4.0)	($0.0)	$13.0	$1.0	$1.1	($0.7)	($0.8)	$12.1	421	54
4	AEP - DOM	Interface	500	$6.0	($2.1)	$0.9	$9.0	$1.0	$4.2	($0.5)	($3.7)	$5.3	1,340	59
5	East	Interface	500	($2.6)	($7.9)	($0.6)	$4.7	$0.1	$0.5	($0.1)	($0.5)	$4.2	190	5
6	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$2.4	$3.2	$0.5	($0.4)	$4.2	160	121
7	Juniata	Transformer	500	$0.4	($0.6)	$0.3	$1.3	$0.2	$0.0	($0.2)	($0.1)	$1.2	0	0
8	Central	Interface	500	($0.8)	($1.4)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	184	2
9	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.8)	($0.8)	($0.7)	7	61
10	Nagel	Line	500	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	30	0
11	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
12	Branchburg - Elroy	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

In the first nine months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges.[27] In the first nine months of 2013, financial companies received $84.1 million, an increase of $16.8 million or 25.0 percent compared to the first nine months of 2012. In the first nine months of 2013, physical companies paid $592.8 million in congestion charges, an increase of $100.3 million or 20.4 percent compared to the first nine months of 2012.

Table 11-34 Congestion cost by type of the participant: January through September 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$41.6	$35.7	$77.3	$83.2	($28.3)	$0.9	($138.1)	($167.3)	$0.0	($84.1)
Physical	$184.7	($488.4)	$44.3	$717.3	$35.1	$111.3	($48.4)	($124.5)	$0.0	$592.8
Total	$226.3	($452.6)	$121.6	$800.5	$6.8	$112.2	($186.4)	($291.8)	$0.0	$508.7

Table 11-35 Congestion cost by type of the participant: January through September 2012

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	($1.7)	$3.2	$54.5	$49.5	($19.8)	($5.5)	($102.5)	($116.8)	$0.0	($67.3)
Physical	$114.8	($406.6)	$32.2	$553.6	$23.5	$49.6	($35.1)	($61.2)	$0.0	$492.5
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$0.0	$425.2

27 The total zonal congestion numbers were calculated as of April 15, 2013 and are, based on continued PJM billing updates, subject to change.

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** At September 30, 2013, 63,765 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,000 MW in the first nine months of 2013. Wind projects account for 16,442 MW of nameplate capacity or 25.7 percent of the capacity in the queues and combined-cycle projects account for 37,634 MW of capacity or 59.0 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-10, 22,070.4 MW is planned to be retired between 2011 and 2019, with all but 614.5 MW retired by June, 2015. The AEP zone accounts for 3,560 MW, or 32.7 percent of all MW planned for deactivation from 2013 through 2019. Since January 1, 2013, 1,437 MW that were scheduled to be deactivated have withdrawn their deactivation notices, and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI zone.
- **Generation Mix.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the Eastern MAAC (EMAAC) and Southwestern MAAC (SWMAAC) locational deliverability areas (LDAs), the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity.[1] Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, despite retirements of coal units.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[2] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built, including 15,726 MW that should already be in service based on the original queue date, but that is not yet even under construction. These projects may also create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

Key Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects. The backbone projects are intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm – Doubs, Jacks Mountain, and Susquehanna – Roseland.

Regional Transmission Expansion Plan (RTEP)

- On October 3, 2013, the PJM Board of Managers authorized $1.2 billion in transmission upgrades and improvements that were identified as part of PJM's continued regional planning process.

1 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones. SWMAAC consists of the BGE and Pepco Control Zones. See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

2 OATT Parts IV & VI.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[3] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition among transmission developers to build transmission projects.[4] The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no evaluation of whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be a goal of PJM market design.

The PJM queue evaluation process needs to be enhanced to ensure that barriers to competition are not created. There appears to be a substantial amount of non-viable MW in the queues, which increase interconnection costs for projects behind them. The MMU recommends the establishment of a PJM review process to ensure that projects are removed from the queue, if they are not viable.

Planned Generation and Retirements

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. On September 30, 2013, 63,765 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,000 MW in 2013. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 12-1).[5] Overall, 731 MW of nameplate capacity were added in PJM in the first nine months of 2013.

3 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

4 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

5 The capacity additions are new MW by year, including full nameplate capacity of solar and wind facilities and are not net of retirements or deratings.

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through the first nine months of 2013[6]

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	2,097
2011	5,008
2012	2,669
2013	731

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months until Queue T, when new queues began to open annually. Queue Z is currently open.

Table 12-2 shows how yearly scheduled capacity has shifted from to 2012 to 2013. The total MW in the queue decreased by 12,622 MW or 16.5 percent from 76,387 MW in 2012 to 63,765 MW as of September 30, 2013. A large portion of that decrease (9,899 MW) was the result of the capacity going into service in 2013.

6 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 12-2 Queue comparison (MW): September 30, 2013 vs. December 31, 2012

	MW in the Queue 2012	MW in the Queue 2013	Year-to-Year Change (MW)	Year-to-Year Change
≤ 2013	22,120	12,221	(9,899)	(44.8%)
2014	8,086	7,474	(613)	(7.6%)
2015	22,295	12,998	(9,297)	(41.7%)
2016	11,788	12,836	1,048	8.9%
2017	8,932	14,505	5,573	62.4%
2018	3,165	1,791	(1,374)	(43.4%)
2019	0	0	0	NA
2020	0	346	346	NA
2024	0	1,594	1,594	NA
Total	76,387	63,765	(12,622)	(16.5%)

Table 12-3 shows the amount of capacity active, in-service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue.[7] Through the first nine months of 2013, 37.9 percent of total in-service capacity from all the queues was from Queues A-C. As of September 30, 2013, withdrawn projects made up, at 257,781 MW or 72.2 percent of the total queue entries. As of September 30, 2013, 9.8 percent of all queued capacity had been placed in service, and 14.0 percent of all queued capacity was either complete or under construction. The MW in queue or under construction is 63,765, about twice what has been completed from the beginning of the process.

7 Projects listed as active have been entered in the queue and the next phase can be under construction, in-service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

Table 12-3 Capacity in PJM queues (MW): At September 30, 2013[8,9]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	14,957	19,602
C Expired 31-Jul-99	0	531	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	1,116	0	17,934	19,050
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	218	0	2,425	2,643
L Expired 31-Jan-04	0	257	0	4,034	4,290
M Expired 31-Jul-04	0	505	150	3,706	4,360
N Expired 31-Jan-05	0	2,399	88	8,040	10,527
O Expired 31-Jul-05	10	1,688	225	5,669	7,592
P Expired 31-Jan-06	43	3,065	463	5,068	8,638
Q Expired 31-Jul-06	120	2,248	2,524	9,642	14,534
R Expired 31-Jan-07	1,296	1,366	748	19,344	22,755
S Expired 31-Jul-07	1,050	3,281	402	12,409	17,142
T Expired 31-Jan-08	3,715	1,275	631	21,936	27,556
U Expired 31-Jan-09	2,151	776	649	29,782	33,358
V Expired 31-Jan-10	3,802	264	2,642	10,298	17,005
W Expired 31-Jan-11	5,089	463	1,978	16,692	24,222
X Expired 31-Jan-12	13,387	219	3,738	13,019	30,363
Y Expired 30-Apr-13	15,029	55	702	10,501	26,286
Z through 30-Jun-13	3,134	0	0	217	3,351
Total	48,825	35,017	14,940	257,781	356,563

The data presented in Table 12-4 show that for successful projects, there is an average time of 2,864 days between entering a queue and the in-service date while for withdrawn projects, there is an average time of 590 days between entering a queue and exiting.

8 The *2013 Quarterly State of the Market Report for PJM: January through September* contains all projects in the queue including reratings of existing generating units and energy only resources.

9 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Table 12-4 Average project queue times (days): At September, 2013

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,266	685	125	4,636
In-Service	2,864	1,354	257	6,027
Suspended	2,059	912	844	3,849
Under Construction	1,583	743	203	6,380
Withdrawn	590	606	0	4,249

Projects with an active status that did not begin construction by October 1, 2013, yet are expected to be complete by January 1, 2015, are defined as non-viable. Such projects are shown in Table 12-5, by expected completion year. There are currently 15,726 MW of non-viable MW in the queues. Non-viable MW decreased by 3,317 MW since last quarter due to withdrawals and project completions. Currently, 61.4 percent of all non-viable generation is located in the AEP and ComEd control zones.

The MMU recommends the establishment of a PJM review process to ensure that projects are removed from the queue, if they are not viable.

Table 12-5 Non-viable MW: Active capacity queued to be in service prior to January 1, 2015, by zone

	2007	2008	2009	2010	2011	2012	2013	2014	Total
AECO	0	0	4	100	274	47	8	350	783
AEP	0	0	0	750	1,047	89	3,115	1,321	6,322
AP	0	0	0	0	32	0	14	1,014	1,060
ATSI	0	0	0	0	175	200	536	212	1,123
BGE	0	0	0	0	0	0	0	0	0
ComEd	27	166	141	220	616	1,390	741	40	3,341
DAY	0	0	0	0	0	200	100	0	300
DEOK	0	0	0	0	0	0	50	4	54
DLCO	0	0	0	0	0	0	0	0	0
Dominion	0	0	0	5	20	20	70	0	115
DPL	0	0	0	20	112	40	27	152	351
EKPC	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	0	0	0	0
Met-Ed	0	35	0	0	0	3	15	150	203
PECO	0	0	0	2	2	71	5	0	80
PENELEC	0	0	70	0	14	84	125	78	370
Pepco	0	0	0	0	0	0	0	16	16
PPL	0	0	0	0	0	0	2	361	362
PSEG	0	0	0	0	0	178	313	756	1,247
Total	27	201	215	1,097	2,292	2,321	5,120	4,454	15,726

Distribution of Units in the Queues

A more detailed examination of the queue data permits some additional conclusions. Table 12-6 shows the projects under construction or active as of September 30, 2013 by unit type and control zone and LDA.[10] The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west, and includes a substantial amount of wind capacity.[11] As of September 30, 2013, 63,765 MW of capacity were in generation request queues for construction through 2024, compared to 72,537 MW at July 1, 2013. Of the 10,883 MW withdrawn from the queues in the past quarter, 6,009 MW were natural gas projects, 2,133 MW were wind projects, and 1,811 MW were coal projects.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (Table 12-6) and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. The western part of the PJM footprint is also likely to see a shift to more natural gas-fired capacity due to changes in environmental regulations and natural gas costs, but likely will maintain a larger amount of coal steam capacity than eastern zones. The replacement of older steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Table 12-6 Capacity additions in active or under-construction queues by control zone and LDA (MW) at September 30, 2013

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	AEC	2,136	71	9	0	0	413	0	0	1,069	3,698
	DPL	1,223	4	16	0	0	218	22	0	297	1,779
	JCPL	1,016	0	30	0	0	766	0	0	0	1,812
	PECO	861	7	4	0	330	0	0	3	0	1,204
	PSEG	3,284	162	9	0	0	157	0	0	0	3,612
	EMAAC Total	**8,520**	**243**	**67**	**00**	**330**	**1,554**	**22**	**03**	**1,366**	**12,105**
SWMAAC	BGE	678	256	4	0	0	22	0	0	0	960
	PEPCO	2,524	0	0	0	0	15	0	0	0	2,540
	SWMAAC Total	**3,202**	**256**	**4**	**0**	**0**	**37**	**0**	**0**	**0**	**3,500**
WMAAC	ME	1,818	0	2	0	50	3	0	0	0	1,873
	PENELEC	879	43	41	20	0	32	0	0	706	1,722
	PPL	4,671	0	7	3	0	9	0	40	399	5,128
	WMAAC Total	**7,368**	**43**	**50**	**23**	**50**	**44**	**0**	**40**	**1,105**	**8,723**
Non-MAAC	AEP	5,682	40	20	0	102	44	313	86	7,653	13,940
	APS	2,009	1,406	49	49	0	2	49	0	408	3,973
	ATSI	2,425	1,484	0	7	0	15	135	0	867	4,933
	ComEd	1,530	216	46	23	120	64	0	41	3,919	5,959
	DAY	0	0	2	112	0	23	12	0	600	749
	DEOK	20	0	0	0	0	0	50	4	0	74
	DLCO	285	0	0	0	48	0	460	0	0	793
	DOM	6,592	60	11	0	1,594	65	172	0	374	8,868
	EKPC	0	0	0	0	0	0	0	0	150	150
	Non-MAAC Total	**18,544**	**3,206**	**129**	**191**	**1,864**	**213**	**1,190**	**131**	**13,971**	**39,438**
Total		**37,634**	**3,748**	**250**	**214**	**2,244**	**1,847**	**1,212**	**174**	**16,442**	**63,765**

10 Unit types designated as reciprocating engines are classified here as diesel.
11 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 16,442 MW of wind resources and 1,847 MW of solar resources, the 63,765 MW currently active in the queue would be reduced to 45,476 MW.

Table 12-7 Existing PJM capacity: At September 30, 2013[12] (By zone and unit type (MW))

	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	706	21	0	0	0	40	1,087	0	8	2,025
AEP	4,900	3,682	63	0	1,072	2,071	0	21,145	0	1,753	34,686
AP	1,129	1,215	48	0	80	0	36	7,358	27	999	10,892
ATSI	685	1,661	73	0	0	2,134	0	6,540	0	0	11,093
BGE	0	835	18	0	0	1,716	0	2,996	0	0	5,565
ComEd	1,770	7,244	100	0	0	10,438	0	5,417	5	2,454	27,428
DAY	0	1,369	48	0	0	0	1	3,180	0	0	4,597
DEOK	0	842	0	0	0	0	0	4,154	0	0	4,996
DLCO	244	15	0	0	6	1,777	0	784	0	0	2,826
Dominion	4,030	3,762	154	0	3,589	3,581	3	8,356	0	0	23,474
DPL	1,125	1,820	96	30	0	0	4	1,800	0	0	4,876
EKPC	0	774	0	0	70	0	0	1,882	0	0	2,726
External	0	111	0	0	0	13	0	4,329	0	0	4,452
JCPL	1,693	1,233	16	0	400	615	42	10	0	0	4,008
Met-Ed	2,051	407	41	0	19	805	0	601	0	0	3,924
PECO	3,209	836	3	0	1,642	4,547	3	979	1	0	11,220
PENELEC	0	344	46	0	513	0	0	6,825	0	931	8,657
Pepco	230	1,092	10	0	0	0	0	3,649	0	0	4,981
PPL	1,808	616	49	0	582	2,520	15	5,529	0	220	11,338
PSEG	3,091	2,838	12	0	5	3,493	105	2,050	2	0	11,597
Total	26,128	31,400	797	30	7,978	33,709	249	88,669	35	6,364	195,359

Table 12-8 shows the age of PJM generators by unit type.

Table 12-8 PJM capacity (MW) by age: at September 30, 2013

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	13,883	4,450	421	30	7	0	249	3,374	35	6,264	28,712
11 to 20	9,287	16,969	131	0	51	0	0	2,738	0	100	29,276
21 to 30	2,517	2,753	56	0	3,316	12,605	0	7,637	0	0	28,884
31 to 40	244	1,415	24	0	241	16,075	0	25,711	0	0	43,709
41 to 50	198	5,813	151	0	2,915	5,029	0	31,721	0	0	45,827
51 to 60	0	0	15	0	112	0	0	14,528	0	0	14,655
61 to 70	0	0	0	0	267	0	0	2,811	0	0	3,078
71 to 80	0	0	0	0	215	0	0	95	0	0	310
81 to 90	0	0	0	0	614	0	0	54	0	0	668
91 to 100	0	0	0	0	108	0	0	0	0	0	108
101 and over	0	0	0	0	131	0	0	0	0	0	131
Total	26,128	31,400	797	30	7,978	33,709	249	88,669	35	6,364	195,359

Table 12-9 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2024. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. New gas-fired capability would represent 95.4 percent of all new capacity in EMAAC when the derating of wind and solar capacity is reflected. In SWMAAC, this value is 99.8 percent. The 79.3 percent of existing capacity in SWMAAC which is steam or nuclear would be reduced, by 2024, to 46.3 percent, and CC and CT generators would comprise 52.9 percent of total capability in SWMAAC.

In Non-MAAC zones, if older units retire, a substantial amount of coal-fired generation would be replaced by wind generation if the units in the generation queues are constructed.[13] In these zones, 88.2 percent of all generation 40 years or older is steam, primarily coal. With the retirement of these units in 2020, wind farms would account for 15.1 percent of total ICAP MW in Non-MAAC zones, if all queued MW are built.

12 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

13 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion Control Zones.

Table 12-9 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2024[14]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2024	Estimated Capacity 2024	Percent of Area Total
EMAAC	Combined Cycle	198	2.2%	9,282	27.5%	8,520	17,604	47.0%
	Combustion Turbine	3,132	34.7%	7,433	22.0%	243	4,544	12.1%
	Diesel	48	0.5%	148	0.4%	67	167	0.4%
	Fuel Cell	0	0.0%	30	1.6%	0	30	2.1%
	Hydroelectric	2,042	22.7%	2,047	6.1%	0	620	1.7%
	Nuclear	615	6.8%	8,654	25.7%	330	8,370	22.4%
	Solar	0	0.0%	194	0.6%	1,554	1,747	4.7%
	Steam	2,981	33.1%	5,926	17.6%	22	2,967	7.9%
	Storage	0	0.0%	3	0.0%	3	6	0.0%
	Wind	0	0.0%	8	0.0%	1,366	1,374	3.7%
	EMAAC Total	9,015	100.0%	33,725	100.0%	12,105	37,429	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	2.2%	3,202	3,432	37.3%
	Combustion Turbine	748	15.4%	1,927	18.3%	256	1,434	15.6%
	Diesel	0	0.0%	28	0.3%	4	32	0.4%
	Hydroelectric	0	0.0%	0	0.0%	0	0	0.1%
	Nuclear	0	0.0%	1,716	16.3%	0	1,716	18.7%
	Solar	0	0.0%	0	0.0%	37	37	0.4%
	Steam	4,099	84.6%	6,645	63.0%	0	2,546	27.7%
	SWMAAC Total	4,847	100.0%	10,546	100.0%	3,500	9,198	100.0%
WMAAC	Combined Cycle	0	0.0%	3,859	16.1%	7,368	11,227	47.4%
	Combustion Turbine	714	7.2%	1,366	5.7%	43	696	2.9%
	Diesel	46	0.5%	136	0.6%	50	139	0.6%
	Hydroelectric	887	9.0%	1,113	4.7%	23	1,136	4.8%
	Nuclear	0	0.0%	3,325	13.9%	50	3,375	14.3%
	Solar	0	0.0%	15	0.1%	44	59	0.2%
	Steam	8,214	83.3%	12,954	54.2%	0	4,741	20.0%
	Storage	0	0.0%	0	0.0%	40	40	0.2%
	Wind	0	0.0%	1,151	4.8%	1,105	2,256	9.5%
	WMAAC Total	9,860	100.0%	23,919	100.0%	8,723	23,668	100.0%
Non-MAAC	Combined Cycle	0	0.0%	12,758	10.0%	18,544	31,302	24.6%
	Combustion Turbine	1,220	3.0%	20,674	16.3%	3,206	22,660	17.8%
	Diesel	72	0.2%	485	0.4%	129	542	0.4%
	Hydroelectric	1,433	3.5%	4,818	3.8%	191	5,008	3.9%
	Nuclear	4,415	10.8%	20,013	15.7%	1,864	17,463	13.8%
	Solar	0	0.0%	40	0.0%	213	253	0.2%
	Steam	33,916	82.6%	63,144	49.7%	1,190	30,418	24.0%
	Storage	0	0.0%	32	0.0%	131	163	0.1%
	Wind	0	0.0%	5,206	4.1%	13,971	19,177	15.1%
	Non-MAAC Total	41,055	100.0%	127,169	100.0%	39,438	126,986	100.0%
All Areas	Total	64,777		195,359		63,765	197,281	

14 Percentages shown in Table 12-9 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Planned Deactivations

As shown in Table 12-10, 22,070.4 MW is planned to be retired between 2011 and 2019, with all but 614.5 MW retired by June, 2015. The AEP zone accounts for 3,560 MW, or 32.7 percent of all MW planned for deactivation from 2013 through 2019. Since January 1, 2013, 1,437 MW that were scheduled to be deactivated have withdrawn their deactivation notices, and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI zone.

Table 12-10 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,196.5
Retirements 2012	6,961.9
Retirements 2013	2,433.8
Planned Retirements 2013	424.6
Planned Retirements 2014	1,870.0
Planned Retirements 2015	8,569.1
Planned Retirements Post-2015	614.5
Total	22,070.4

Figure 12-1 Map of unit retirements in PJM: 2012 through 2019

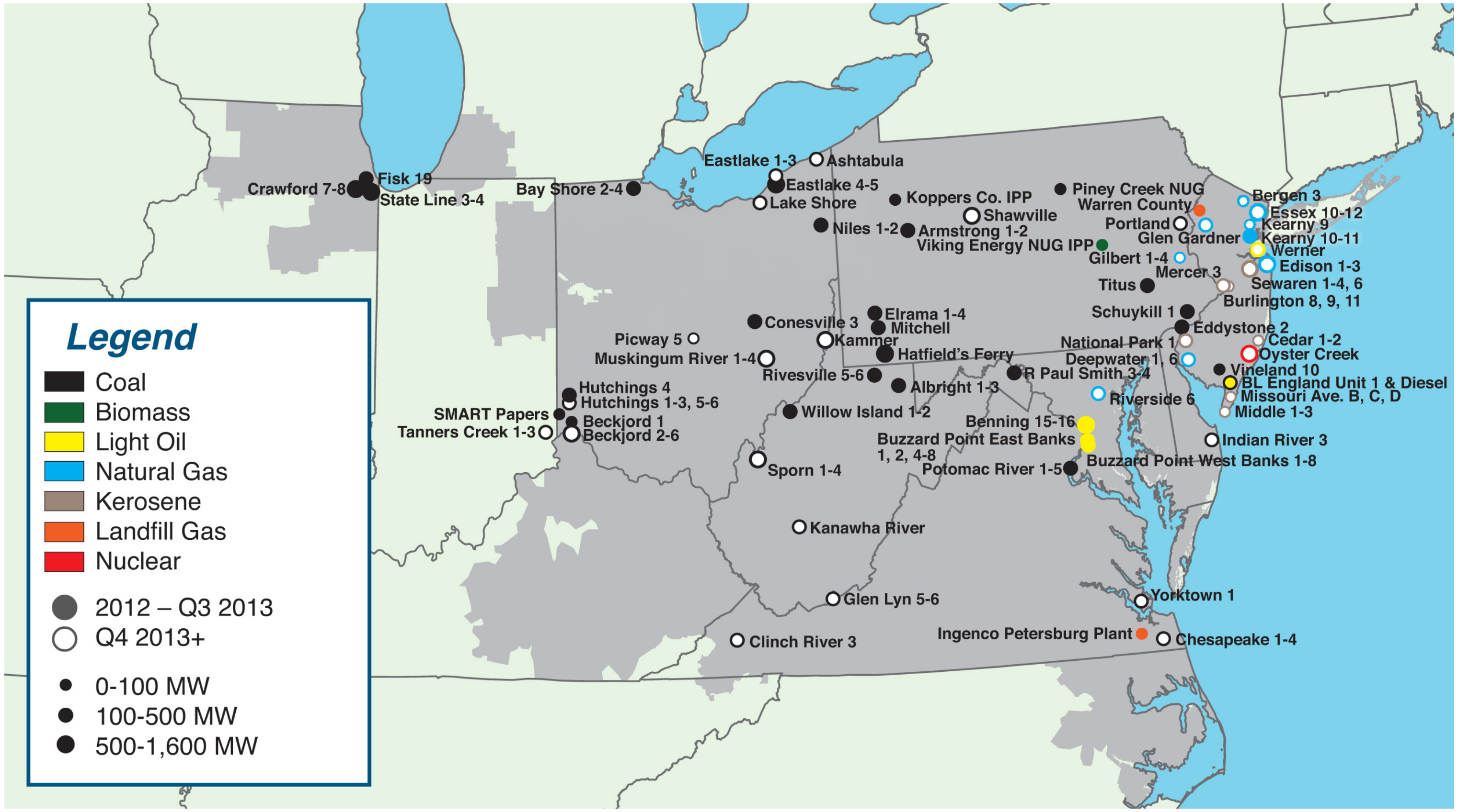


Table 12-11 Planned deactivations of PJM units, as of October 10, 2013

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
Warren County Landfill	JCPL	1.9	Landfill Gas	Reciprocating engine	09-Jan-13
Piney Creek NUG	PENELEC	31.0	Waste Coal	Steam	12-Apr-13
Walter C Beckjord 2-3	DEOK	222.0	Coal	Steam	21-Nov-13
Indian River 3	DPL	169.7	Coal	Steam	31-Dec-13
BL England 1	AECO	113.0	Coal	Steam	01-May-14
Deepwater 1, 6	AECO	158.0	Natural gas	Steam	31-May-14
Riverside 6	BGE	115.0	Natural gas	Combustion Turbine	01-Jun-14
Portland	Met-Ed	401.0	Coal	Steam	01-Jun-14
Burlington 9	PSEG	184.0	Kerosene	Combustion Turbine	01-Jun-14
Chesapeake 1-4	Dominion	576.0	Coal	Steam	31-Dec-14
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Dec-14
Beckjord 4-6	DEOK	802.0	Coal	Steam	01-Apr-15
Shawville 1-7	PENELEC	603.0	Coal	Steam	16-Apr-15
Gilbert 1-4	JCPL	98.0	Natural gas	Combustion Turbine	01-May-15
Glen Gardner 1-8	JCPL	160.0	Natural gas	Combustion Turbine	01-May-15
Werner 1-4	JCPL	212.0	Light oil	Combustion Turbine	01-May-15
Kearny 9	PSEG	21.0	Natural gas	Combustion Turbine	01-May-15
Cedar 1-2	AECO	65.6	Kerosene	Combustion Turbine	31-May-15
Middle 1-3	AECO	74.7	Kerosene	Combustion Turbine	31-May-15
Missouri Ave B, C, D	AECO	57.9	Kerosene	Combustion Turbine	31-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	31-May-15
Clinch River 3	AEP	230.0	Coal	Steam	01-Jun-15
Glen Lyn 5-6	AEP	325.0	Coal	Steam	01-Jun-15
Kammer 1-3	AEP	600.0	Coal	Steam	01-Jun-15
Kanawha River 1-2	AEP	400.0	Coal	Steam	01-Jun-15
Muskingum River 1-4	AEP	790.0	Coal	Steam	01-Jun-15
Picway 5	AEP	95.0	Coal	Steam	01-Jun-15
Sporn 1-4	AEP	580.0	Coal	Steam	01-Jun-15
Tanners Creek 1-3	AEP	488.1	Coal	Steam	01-Jun-15
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Eastlake 1-3	ATSI	327.0	Coal	Steam	01-Jun-15
Lake Shore	ATSI	190.0	Coal	Steam	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Burlington 8, 11	PSEG	205.0	Kerosene	Combustion Turbine	01-Jun-15
Edison 1-3	PSEG	504.0	Natural gas	Combustion Turbine	01-Jun-15
Essex 10-11	PSEG	352.0	Natural gas	Combustion Turbine	01-Jun-15
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
National Park 1	PSEG	21.0	Kerosene	Combustion Turbine	01-Jun-15
Sewaren 1-4	PSEG	453.0	Natural gas	Steam	01-Jun-15
Sewaren 6	PSEG	105.0	Kerosene	Combustion Turbine	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		11,478.2			

Table 12-12 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 74.2 percent, of all MW retiring during this period are coal steam units. These units have an average age of 57 years, and an average size of 162 MW. This indicates that, on average, retirements have consisted of smaller sub-critical coal steam units, and those without adequate environmental controls to remain viable beyond 2015.

Table 12-12 Deactivations of PJM units, 2011 through 2019

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW
Coal	101	161.7	57.1	16,333.4
Diesel	03	5.6	43.3	16.9
Heavy Oil	01	166.0	55.0	166.0
Kerosene	20	41.4	45.5	828.2
LFG	01	1.9	7.0	1.9
Light Oil	15	76.6	43.8	1,148.7
Natural Gas	49	57.9	46.8	2,838.5
Nuclear	01	614.5	50.0	614.5
Waste Coal	01	31.0	20.0	31.0
Wood Waste	02	12.0	23.5	24.0

Table 12-13 HEDD Units in PJM as of September30, 2013[15]

Unit	Zone	MW	Deactivation Date
Carlls Corner 1-2	AECO	72.6	NA
Cedar Station 1-3	AECO	66.0	31-May-15
Cumberland 1	AECO	92.0	NA
Mickleton 1	AECO	72.0	NA
Middle Street 1-3	AECO	75.3	31-May-15
Missouri Ave. B,C,D	AECO	60.0	31-May-15
Sherman Ave.	AECO	92.0	NA
Vineland West CT	AECO	26.0	01-Sep-12
Forked River 1-2	JCPL	65.0	NA
Gilbert 4-7, 9, C1-C4	JCPL	446.0	01-May-15
Glen Gardner A1-A4, B1-B4	JCPL	160.0	01-May-15
Lakewood 1-2	JCPL	316.1	NA
Parlin NUG	JCPL	114.0	NA
Sayreville C1-C4	JCPL	224.0	NA
South River NUG	JCPL	299.0	NA
Werner C1-C4	JCPL	212.0	01-May-15
Bayonne	PSEG	118.5	NA
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 111-114, 121-124, 91-94, 8	PSEG	557.0	01-Jun-15
Camden	PSEG	145.0	NA
Eagle Point 1-2	PSEG	127.1	NA
Edison 11-14, 21-24, 31-34	PSEG	504.0	01-Jun-15
Elmwood	PSEG	67.0	NA
Essex 101-104, 111-114, 121,124	PSEG	536.0	01-Jun-15
Kearny 9-11, 121-124	PSEG	446.0	01-May-15
Linden 1-2	PSEG	1,230.0	NA
Mercer 3	PSEG	115.0	01-Jun-15
National Park	PSEG	21.0	01-Jun-15
Newark Bay	PSEG	120.2	NA
Pedricktown	PSEG	120.3	NA
Salem 3	PSEG	38.4	NA
Sewaren 6	PSEG	105.0	01-Jun-15
Total		6,663.5	

15 See *"Current New Jersey Turbines that are HEDD Units,"* <http://www.state.nj.us/dep/workgroups/docs/apcrule_20110909turbinelist.pdf> (Accessed July 1, 2013)

Actual Generation Deactivations in 2013

Table 12-14 shows unit deactivations for 2013 through October 9, 2013.[16] A total of 2,433.8 MW retired from January 1, 2013, through October 9, 2013.

Table 12-14 Unit deactivations: January 2013 through October 9, 2013

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Exelon Corporation	Schuylkill 1	166.0	Heavy Oil	PECO	54	01-Jan-13
Exelon Corporation	Schuylkill Diesel	3.0	Diesel	PECO	45	01-Jan-13
Ingenco Wholesale Power, LLC	Ingenco Petersburg	2.9	Diesel	Dominion	22	31-May-13
The AES Corporation	Hutchings 4	61.9	Coal	DAY	62	01-Jun-13
NRG Energy	Titus 1	81.0	Coal	MetEd	63	01-Sep-13
NRG Energy	Titus 2	81.0	Coal	MetEd	62	01-Sep-13
NRG Energy	Titus 3	81.0	Coal	MetEd	60	01-Sep-13
NextEra Energy	Koppers Co. IPP	08.0	Wood waste	PPL	24	30-Sep-13
First Energy	Hatfield's Ferry 1	530.0	Coal	AP	44	09-Oct-13
First Energy	Hatfield's Ferry 2	530.0	Coal	AP	43	09-Oct-13
First Energy	Hatfield's Ferry 3	530.0	Coal	AP	42	09-Oct-13
First Energy	Mitchell 2	82.0	Coal	AP	65	09-Oct-13
First Energy	Mitchell 3	277.0	Coal	AP	50	09-Oct-13

Updates on Key Backbone Facilities

PJM baseline upgrade projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of baseline upgrade projects that have been given the informal designation of backbone due to their relative significance. Backbone upgrades are on the EHV (Extra High Voltage) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are Mount Storm – Doubs, Jacks Mountain, and Susquehanna – Roseland.

The Mount Storm – Doubs transmission line, which serves West Virginia, Virginia, and Maryland, was originally built in 1966. The structures and equipment are approaching the end of their expected service life and require replacement to ensure reliability in its service areas. "As of September, 2013, construction is proceeding ahead of schedule. All structure foundations are

16 See *"PJM Generator Deactivations,"* PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (October 1, 2013).

complete, approximately 70 percent of the structures have been erected, and more than 70 percent of the line is complete."[17]

The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh – Juniata and Keystone – Juniata 500kV circuits. The plans are for construction of the foundation in late 2013, construction in 2014 and completion in early 2015.

The Susquehanna – Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna – Roseland will be a new 500kV transmission line connecting the Susquehanna – Lackawanna – Hopatcong – Roseland buses. On October 1, 2012, the Susquehanna – Roseland project received final approval from the National Park Service (NPS) for the project to be constructed on the route selected by PSEG and PPL.[18] The Susquehanna – Hopatcong portion of the project is currently expected to be in-service by June 2014, with the remainder of the project to be completed by June, 2015.

Regional Transmission Expansion Plan (RTEP)

On October 3, 2013, the PJM Board of Managers authorized $1.2 billion in transmission upgrades and improvements identified as part of PJM's continued regional planning process. Table 12-15 shows the upgrades by transmission owner.

Table 12-15 Estimated approved upgrade costs by transmission owner (dollars (Millions))

Transmission Owner	Cost Estimate
AEC	$60.1
AEP	$308.9
APS	$110.6
ATSI	$17.6
BGE	$69.5
DL	$17.6
Dominion	$73.8
DPL	$16.3
EKPC	$22.3
JCPL	$8.9
NRG Energy	$0.7
PECO	$5.8
PENELEC	$7.2
PEPCO	$16.0
PPL	$219.3
PSEG	$267.1
Total	$1,221.4

Regional Transmission Expansion Plan (RTEP) Proposal Windows

On July 22, 2013, PJM made a second filing in compliance with Order No. 1000 and in compliance with the order on its first compliance filing issued March 22, 2013.[19] PJM's Order No. 1000 compliance filing addressed a number of procedural issues identified by the Commission in the March 22 order. In the initial filing PJM proposed to expand the regional planning process to provide greater opportunity for non-incumbent transmission developers to submit solution proposals.[20] PJM's filing established proposal windows for competitive solicitations but limited the ability of competitors to make proposals within a defined time window.[21]

A test of whether PJM's new process can operate transparently and offer a meaningful opportunity for non-incumbents to compete involves Artificial

17 See *"Mt. Storm – Doubs 500kV Rebuild Project,"* Dom.com <https://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (October 11, 2013).
18 See PSEG.com. "Susquehanna-Roseland line receives final federal approval," <http://www.pseg.com/info/media/newsreleases/2012/2012-10-02.jsp> (Accessed July 30, 2013).

19 PJM filing, Docket No. ER13-198-002 (July 22nd PJM Filing"); 142 FERC ¶ 61,214. PJM Transmission Owners made a separate filing addressing cost allocation issues, also on March 22, 2013.
20 PJM compliance filing, Docket No. ER13-198-001 (October 25, 2012).
21 Id.; see also *"RTEP Proposal Windows,"* PJM.com <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx> (Accessed July 30, 2013).

Island, which includes the Salem and Hope Creek nuclear plants. On April 29, 2013, PJM submitted a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and to eliminate potential planning criteria violations in the Artificial Island Area. The RFP window closed on June 28, 2013. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSEG, and a range of proposals from other non-incumbents. The costs of solutions proposed ranged from approximately $54 million to $1.4 billion.[22] These proposals are currently being evaluated by PJM.

22 See *"PJM 2013 RTEP Proposal Window Tracking,"* PJM.com <http://www.pjm.com/~/media/committees-groups/committees/teac/20130710/20130710-pjm-2013-rtep-proposal-window-tracking.ashx> (Accessed July 30, 2013).

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates were the beneficiaries of the system through access to low cost energy via the transmission system.

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system.[1] Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and that load pays the constrained price which creates the funds available to offset congestion costs in an LMP market.[2,3] It is load overpayment for generation in an LMP system that is the source of revenues for FTR funding. FTRs are are simply a mechanism to return the overpayment to load.

The *2013 Quarterly State of the Market Report for PJM: January through September*, focuses on the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period, which covers June 1, 2013, through September 30, 2013.

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259-62,260 & n. 123.
3 For a more complete explanation, see the *2012 State of the Market Report for PJM*, Volume II, Section 12, "FTRs."

Table 13-1 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as mixed because while there are many positive features of the FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several features of the FTR design which result in underfunding and features of the FTR design which incorporate subsidies which also contribute to underfunding. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can also sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period through September 30, 2013, total participant FTR sell offers were 2,334,947 MW, up from 2,217,995 MW for the same period during the 2012 to 2013 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 5.9

percent from 9,223,203 MW for the first four months of the prior planning period, to 9,765,083 MW.

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 75.6 percent of prevailing flow and 85.7 percent of counter flow FTRs for January through September of 2013. Financial entities owned 62.2 percent of all prevailing and counter flow FTRs, including 53.4 percent of all prevailing flow FTRs and 79.4 percent of all counter flow FTRs during the January through September 2013 period.

Market Behavior

- **FTR Forfeitures.** Total forfeitures of FTR profits resulting from the FTR forfeiture rule for the 2013 to 2014 planning period, through August 2013, were $440,526 for Increment Offers and Decrement Bids.
- **Credit Issues.** Eight participants defaulted in 2013, through August, from twelve default events. The average of these defaults was $320,125 with nine based on inadequate collateral and three based on nonpayment. The average collateral default was $377,579 and the average nonpayment default was $147,761. The majority of these defaults were promptly cured, with one partial cure. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** For the 2013 to 2014 planning period, through September 2013, the Monthly Balance of Planning Period FTR Auctions cleared 1,308,752 MW (13.4 percent) of FTR buy bids and 443,885 MW (19.0 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period, through September 2013, was $0.07, down from $0.11 per MW for the same time period in the 2012 to 2013 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $7.3 million in net revenue for all FTRs for the first four months of the 2013 to 2014 planning period, down from $11.9 million for the same time period in the 2012 to 2013 planning period.
- **Revenue Adequacy.** FTRs were paid at 67.8 percent of the target allocation for the entire 2012 to 2013 planning period. FTRs were paid at 77.3 percent of the target allocation level for the first four months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $287.4 million of FTR revenues during the 2013 to 2014 planning period through September 30, 2013 and $614.0 million during the 2012 to 2013 planning period.

  For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion Zone and Northern Illinois Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were Vienna and Western Hub.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $138.8 million in profits for physical entities, of which $134.0 million was from self-scheduled FTRs, and $132.1 million for financial entities. As shown in Table 13-9, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in March 2013.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the Annual ARR Allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. For the 2013 to 2014 planning period, through September 2013, PJM allocated a total of 11,586.4 MW of residual ARRs with a total target allocation of $3.3 million.

- **ARR Reassignment for Retail Load Switching.** There were 25,157 MW of ARRs associated with approximately $125,800 of revenue that were reassigned in the first four months of the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2013 to 2014 planning period, the ARR target allocations were $503.4 million while PJM collected $559.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2012 to 2013 planning period, the ARR target allocations were $565.4 million while PJM collected $614.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate for that period.
- **ARRs and FTRs as an Offset to Congestion.** The effectiveness of ARRs as an offset to congestion can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2013 to 2014 planning period through September 30, 2013, the total revenues received by ARR holders, including self-scheduled FTRs, offset 85.5 percent of the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2012 to 2013 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 92.6 percent of the total congestion costs within PJM and for the 2011 to 2012 planning period 88.9 percent.

Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.

Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. ARRs now serve that function. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. In the PJM model, FTRs are a financial product that PJM makes available when excess transmission capability permits.

Revenue adequacy has received a lot of attention in the PJM FTR market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and real-time markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2013 the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. The MMU recommends that the calculation of the monthly FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling in the FTR auction model which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real time markets, including reactive interfaces, which directly results in differences in congestion between day ahead and real time markets; differences in day-ahead and real time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load, which directly results in differences in congestion between day ahead and real time markets; the overallocation of ARRs which directly results in underfunding; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to FTR underfunding; and the continued sale of FTR capability on persistently underfunded pathways. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion.

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths, subject to revenue availability. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[4] The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation is a cap on what FTR holders can receive. Revenues above that level on individual FTR paths are used to fund FTRs on paths which received less than their target allocations. Available revenue to pay FTR holders is based on the amount of Day-Ahead and balancing congestion collected, along with Market to Market payments, excess ARR revenues available at the end of a month and any charges made to Day-Ahead Operating Reserves.

4 For additional information on marginal losses, see the *2012 State of the Market Report for PJM*, Volume II, Section 10, "Congestion and Marginal Losses," at "Marginal Losses."

FTR funding is on an aggregate basis and is not on a path specific basis or on a time specific basis. As a result, there are widespread cross subsidies paid to equalize payments across paths and across time periods within a planning period. All paths receive the same proportional level of target revenue at the end of the planning period. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. Revenues to fund FTRs come from both day-ahead congestion charges on the transmission system and balancing congestion charges. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. When FTR holders receive their target allocations, the associated FTRs are considered fully funded. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self-scheduled bids are FTRs that have been directly converted from ARRs in the Annual FTR Auction.

There are two types of FTR products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three classes of FTR products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

PJM operates an Annual FTR Auction for all participants. In addition, PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, which allows participants to buy and sell residual transmission capability. PJM also runs a Long Term FTR Auction for the following three consecutive planning years. FTR options are not available in the Long Term FTR Auction. A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets.

FTR buy bids and sell offers may be made as obligations or options and as any of the three classes. FTR self-scheduled bids are available only as obligations and 24-hour class, consistent with the associated ARRs, and only in the Annual FTR Auction.

As one of the measures to address FTR funding, effective August 5, 2011, PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path.

Market Structure

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply and Demand

PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[5] FTRs can also be traded

5 See PJM. "Manual 6: Financial Transmission Rights," Revision 13 (June 28, 2012), p. 38.

between market participants through bilateral transactions. ARRs may be self scheduled as FTRs for participation only in the Annual FTR Auction.

Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible including self scheduled ARRs. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included in the model, while known outages of five days or more are included in the model for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[6]

But the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages. In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model may have significant distributional consequences.

These issues are a reason to implement probabilistic outage modeling, seasonal ARR allocations and explicit rules governing the treatment of non simultaneous outages during an FTR auction period.

Monthly Balance of Planning Period FTR Auctions

The residual capability of the PJM transmission system, after the Long Term and Annual FTR Auctions are concluded, is offered in the Monthly Balance of Planning Period FTR Auctions. Existing FTRs are modeled as fixed injections and withdrawals. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the planning period. FTRs in the auctions include obligations and options and 24-hour, on peak and off peak products.[7]

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

Buy Bids

The total FTR buy bids in the 2013 to 2014 Annual FTR Auction were 3,274,373 MW. The total FTR buy bids in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period were 19,685,688 MW.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions.

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily

6 See PJM. "Manual 6: Financial Transmission Rights," Revision 13 (June 28, 2012), p. 54.

7 See PJM. "Manual 6: Financial Transmission Rights," Revision 13 (June 28, 2012), p. 39.

take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-2 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through September 2013 by trade type, organization type and FTR direction. Financial entities purchased 75.6 percent of prevailing flow and 85.7 percent of counter flow FTRs for the first nine months of the year, with the result that financial entities purchased 79.6 percent of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through September 2013.

Table 13-2 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September 2013

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	24.4%	14.3%	20.4%
	Financial	75.6%	85.7%	79.6%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	32.5%	28.6%	31.9%
	Financial	67.5%	71.4%	68.1%
	Total	100.0%	100.0%	100.0%

Table 13-3 presents the daily net position ownership for all FTRs for January through September 2013, by FTR direction.

Table 13-3 Daily FTR net position ownership by FTR direction: January through September 2013

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	46.6%	20.6%	37.8%
Financial	53.4%	79.4%	62.2%
Total	100.0%	100.0%	100.0%

Market Behavior

FTR Forfeitures

An FTR holder may be subject to forfeiture of any profits from an FTR if it meets the criteria defined in Section 5.2.1 (b) of Schedule 1 of the PJM Operating Agreement, the FTR forfeiture rule. If a participant has a cleared increment offer or decrement bid for an applicable hour at or near the source or sink of any FTR they own and the day-ahead congestion LMP difference is greater than the real time congestion LMP difference the profits from that FTR may be subject to forfeiture for that hour. An increment offer or decrement bid is considered near the source or sink point if 75 percent or more of the energy injected or withdrawn, and which is withdrawn or injected at any other bus, is reflected on the constrained path between the FTR source or sink. This rule only applies to increment offers and decrement bids that would increase the price separation between the FTR source and sink points.

Figure 13-1 demonstrates the FTR forfeiture rule for INCs and DECs. The INC or DEC distribution factor (dfax) is compared to the largest impact withdrawal or injection dfax. If the absolute difference between the virtual bid and its counterpart is greater than or equal to 75 percent, the virtual bid is considered for forfeiture. This is the metric in the rule which defines the impact of the virtual bid on the constraint.

In the first part of the example in Figure 13-1, the INC has a dfax of 0.25 and the maximum withdrawal dfax on the constraint is -0.5. The difference between the two dfaxes is -0.75 (0.25 minus -0.5). The absolute value is 0.75. In the second part of the example in Figure 13-1, the DEC has dfax of 0.5 and the maximum injection dfax on the constraint is -0.25. The difference between the two dfaxes is 0.75 (-0.25 minus 0.5). The absolute value is also 0.75.

Figure 13-1 Illustration of INC/DEC FTR forfeiture rule

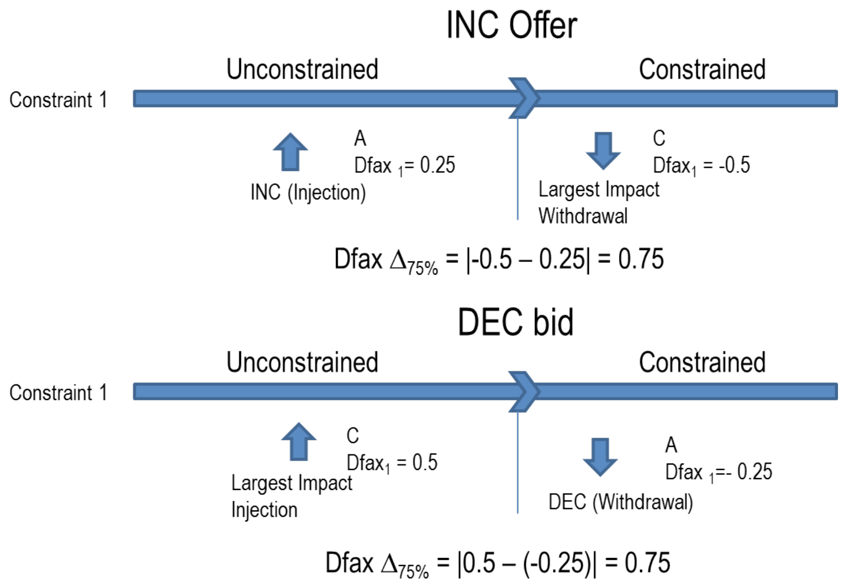
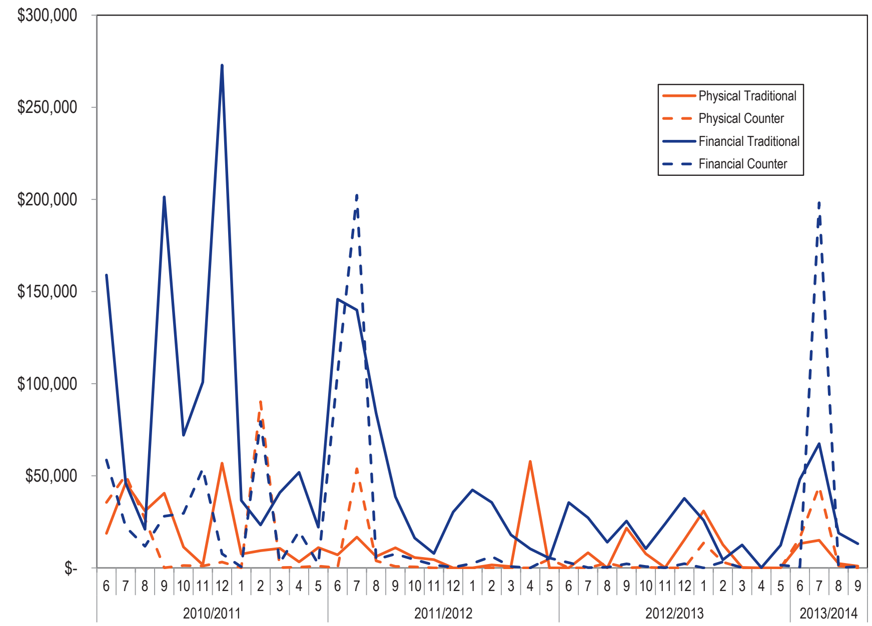


Figure 13-2 shows the FTR forfeitures values for both counter flow and prevailing flow FTRs for each month of June 2010 through September 2013 by company type.[8] Currently, FTRs that alleviate a constraint are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the 2013 to 2014 planning period, through September 2013, were $440,526 (0.1 percent of total FTR target allocations).[9]

Figure 13-2 Monthly FTR Forfeitures for physical and financial participants: June 2010 through September 2013



Credit Issues

The credit issues reported here were not necessarily related to FTR positions.

Eight participants defaulted during 2013, through August, from twelve default events. The average of these defaults was $320,125 with nine based on inadequate collateral and three based on nonpayment. The average collateral default was $377,579 and the average nonpayment default was $147,761. The majority of these defaults were promptly cured, with one partial cure.

8 Counter flow FTRs are defined for this purpose as FTRs with a negative auction price.
9 Forfeiture total is different in this State of the Market Report than previous due to adjustments made to correct errors in August 2012, September 2012, November 2012 and April 2013.

Market Performance

Volume

Table 13-4 Monthly Balance of Planning Period FTR Auction market volume: January through September 2013

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-13	Obligations	Buy bids	150,397	963,036	166,622	17.3%	796,414	82.7%
		Sell offers	84,563	297,609	34,710	11.7%	262,899	88.3%
	Options	Buy bids	2,830	104,318	6,767	6.5%	97,551	93.5%
		Sell offers	10,204	73,624	17,322	23.5%	56,302	76.5%
Feb-13	Obligations	Buy bids	164,620	1,035,756	166,386	16.1%	869,369	83.9%
		Sell offers	76,210	261,631	36,402	13.9%	225,229	86.1%
	Options	Buy bids	2,518	94,039	4,749	5.0%	89,290	95.0%
		Sell offers	9,053	62,833	16,434	26.2%	46,399	73.8%
Mar-13	Obligations	Buy bids	168,718	1,092,986	188,849	17.3%	904,138	82.7%
		Sell offers	77,248	256,820	40,079	15.6%	216,741	84.4%
	Options	Buy bids	2,674	103,046	5,591	5.4%	97,455	94.6%
		Sell offers	10,054	84,993	21,581	25.4%	63,411	74.6%
Apr-13	Obligations	Buy bids	130,671	742,450	143,747	19.4%	598,703	80.6%
		Sell offers	55,739	206,725	33,203	16.1%	173,522	83.9%
	Options	Buy bids	1,852	47,911	4,069	8.5%	43,842	91.5%
		Sell offers	6,017	58,130	17,259	29.7%	40,870	70.3%
May-13	Obligations	Buy bids	99,964	562,240	119,522	21.3%	442,718	78.7%
		Sell offers	25,028	93,603	19,917	21.3%	73,686	78.7%
	Options	Buy bids	792	33,223	2,901	8.7%	30,322	91.3%
		Sell offers	2,634	24,643	15,506	62.9%	9,137	37.1%
Jun-13	Obligations	Buy bids	268,004	1,548,839	275,485	17.8%	1,273,354	82.2%
		Sell offers	150,754	474,950	59,536	12.5%	415,415	87.5%
	Options	Buy bids	4,155	313,972	14,825	4.7%	299,147	95.3%
		Sell offers	23,090	198,850	55,455	27.9%	143,395	72.1%
Jul-13	Obligations	Buy bids	296,234	2,006,362	281,879	14.0%	1,724,483	86.0%
		Sell offers	142,594	429,555	57,422	13.4%	372,133	86.6%
	Options	Buy bids	10,303	564,738	16,412	2.9%	548,326	97.1%
		Sell offers	20,146	140,558	51,541	36.7%	89,018	63.3%
Aug-13	Obligations	Buy bids	337,418	2,283,124	334,179	14.6%	1,948,945	85.4%
		Sell offers	133,353	385,475	61,167	15.9%	324,309	84.1%
	Options	Buy bids	8,850	443,384	12,719	2.9%	430,665	97.1%
		Sell offers	21,320	147,295	45,916	31.2%	101,379	68.8%
Sep-13	Obligations	Buy bids	316,757	2,128,460	354,081	16.6%	1,774,379	83.4%
		Sell offers	186,831	421,145	65,522	15.6%	355,623	84.4%
	Options	Buy bids	8,735	476,204	19,173	4.0%	457,032	96.0%
		Sell offers	20,991	137,118	47,328	34.5%	89,790	65.5%
2012/2013*	Obligations	Buy bids	2,255,105	12,956,832	2,171,751	16.8%	10,785,081	83.2%
		Sell offers	1,080,775	3,922,225	468,426	11.9%	3,453,798	88.1%
	Options	Buy bids	103,926	6,728,856	74,889	1.1%	6,653,967	98.9%
		Sell offers	149,274	1,088,211	268,684	24.7%	819,527	75.3%
2013/2014**	Obligations	Buy bids	1,218,413	7,966,785	1,245,623	15.6%	6,721,161	84.4%
		Sell offers	613,532	1,711,126	243,646	14.2%	1,467,479	85.8%
	Options	Buy bids	32,043	1,798,298	63,129	3.5%	1,735,169	96.5%
		Sell offers	85,547	623,821	200,239	32.1%	423,583	67.9%

* Shows Twelve Months for 2012/2013; ** Shows four months ended 30-Sep-13 for 2013/2014

Table 13-4 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2012 to 2013 planning period and the first four months of the 2013 to 2014 planning period. There were 7,966,785 MW of FTR buy bid obligations and 1,711,126 MW of FTR sell offer obligations for all bidding periods in the 2013 to 2014 planning period. The 2013 to 2014 planning period Monthly Balance of Planning Period Auctions cleared 1,245,623 MW (15.6 percent) of FTR buy bid obligations and 243,646 MW (14.2 percent) of FTR sell offer obligations.

There were 1,798,298 MW of FTR buy bid options and 623,821 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period. The monthly auctions cleared 63,129 MW (3.5 percent) of FTR buy bid options, and 200,239 MW (32.1 percent) of FTR sell offers.

Table 13-5 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume. The average monthly cleared volume for January through September 2013 is 235,328.3 MW. The average monthly cleared volume for January through September 2012 was 176,697.9 MW.

Table 13-5 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): January through September 2013

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	Bid	595,260	191,417	115,207				165,471	1,067,354
	Cleared	125,075	24,018	8,251				16,045	173,389
Feb-13	Bid	654,446	174,360	177,548				123,440	1,129,794
	Cleared	131,562	15,659	13,975				9,939	171,135
Mar-13	Bid	645,247	232,876	224,105				93,804	1,196,032
	Cleared	136,007	27,219	24,669				6,544	194,440
Apr-13	Bid	610,571	179,789						790,360
	Cleared	127,896	19,920						147,816
May-13	Bid	595,463							595,463
	Cleared	122,423							122,423
Jun-13	Bid	766,947	218,427	205,723	112,180	195,196	193,766	170,571	1,862,810
	Cleared	141,332	31,035	25,346	14,149	27,397	25,560	25,491	290,310
Jul-13	Bid	921,277	343,637	244,602	0	329,350	349,639	382,594	2,571,100
	Cleared	158,643	30,086	15,959	0	27,840	34,134	31,628	298,291
Aug-13	Bid	1,076,550	268,252	266,570	0	331,723	393,247	390,165	2,726,508
	Cleared	178,551	26,336	22,399	0	30,116	47,483	42,012	346,898
Sep-13	Bid	934,389	330,547	344,156	0	250,625	375,174	369,773	2,604,664
	Cleared	188,437	37,569	36,258	0	23,153	45,357	42,480	373,253

Figure 13-3 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through September 2013, by type of auction. FTR volumes are included in the calendar month they are effective, with Long Term and Annual FTR auction volume spread equally to each month in the relevant planning period. This figure shows the share of FTRs purchased in each auction type by month. Over the course of the planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater portion of active FTRs. When the Annual FTR Auction occurs, FTRs purchased in any previous Monthly Balance of Planning Period Auction, other than the current June auction, are no longer in effect, so there is a reduction in their share of total FTRs with an accompanying rise in the share of Annual FTRs.

Figure 13-3 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through September 2013

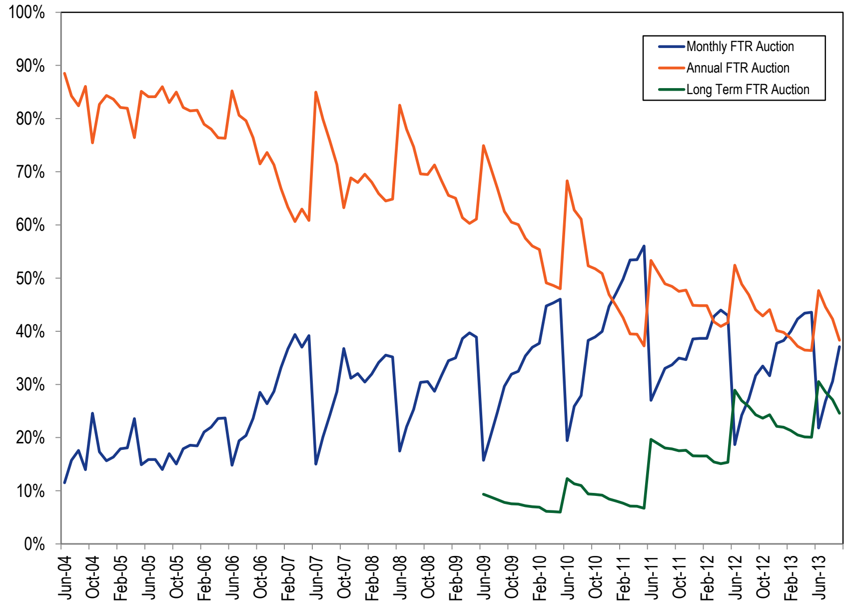


Table 13-6 provides the secondary bilateral FTR market volume for the entire 2012 to 2013 planning period and the first four months of the 2013 to 2014 planning period.

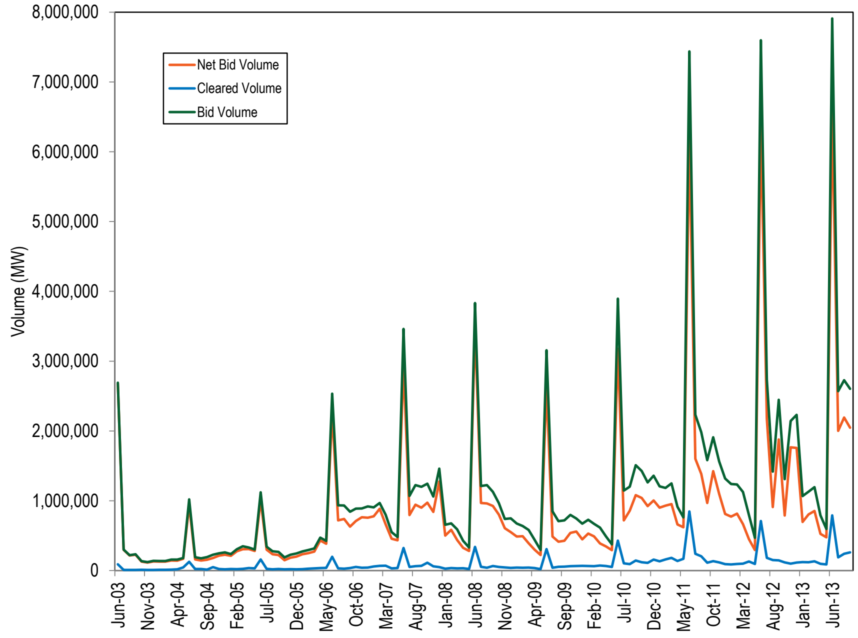
Table 13-6 Secondary bilateral FTR market volume: Planning periods 2012 to 2013 and 2013 to 2014[10]

Planning Period	Hedge Type	Class Type	Volume (MW)
2012/2013	Obligation	24-Hour	95
		On Peak	137
		Off Peak	60
		Total	292
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0
2013/2014	Obligation	24-Hour	110
		On Peak	41,590
		Off Peak	34,178
		Total	75,879
	Option	24-Hour	0
		On Peak	9,724
		Off Peak	914
		Total	10,638

Figure 13-4 shows the FTR bid, cleared and net bid volume from June 2003 through September 2013 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume is the volume of FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self-scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self-scheduled offers, excluding sell offers. Bid volumes and net bid volumes have increased since 2003. Cleared volume was relatively steady until 2010, with an increase in 2011 followed by a slight decrease in 2012. The demand for FTRs has increased while availability of FTRs generally did not increase until 2011.

10 The 2013 to 2014 planning period covers bilateral FTRs that are effective for any time between June 1, 2013 through September 30, 2013, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 13-4 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through September 2013



Price

Table 13-7 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2013 through September 2013. For example, for the January 2013 Monthly Balance of Planning Period FTR Auction, the current month column is January, the second month column is February and the third month column is March. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the January 2013 Monthly Balance of Planning Period FTR Auction.

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for January through September 2013 was $0.09 per MW, down from $0.10 per MW in the same time last year.

Table 13-7 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through September 2013

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	$0.11	$0.20	$0.05				$0.09	$0.11
Feb-13	$0.09	$0.12	$0.10				$0.13	$0.10
Mar-13	$0.10	$0.12	$0.10				$0.05	$0.10
Apr-13	$0.10	$0.16						$0.11
May-13	$0.09	$0.00						$0.09
Jun-13	$0.08	$0.21	$0.19	$0.15	$0.16	$0.14	$0.10	$0.06
Jul-13	$0.10	$0.17	($0.14)		$0.12	$0.07	$0.06	$0.08
Aug-13	$0.08	$0.17	$0.07		$0.07	$0.07	$0.06	$0.08
Sep-13	$0.06	$0.07	$0.04		$0.11	$0.09	$0.06	$0.07

Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. For a prevailing flow FTR, the FTR credits are the actual revenue that an FTR holder receives and the auction price is the cost. For a counter flow FTR, the auction price is the revenue that an FTR holder is paid and the FTR credits are the cost to the FTR holder, which the FTR holder must pay. The cost of self-scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction, but the ARR holders receive offsetting ARR credits that equal the purchase price of the FTRs.

Table 13-8 lists FTR profits by organization type and FTR direction for the period from January through September, 2013. FTR profits are the sum of the daily FTR credits, including for self-scheduled FTRs, minus the daily FTR auction costs for each FTR held by an organization. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days, but self-scheduled FTRs have zero cost. FTRs were profitable overall, with $138.8 million in profits for physical entities, of which $135.9 million was from self-scheduled FTRs, and $132.1 million for financial entities.

Table 13-8 FTR profits by organization type and FTR direction: January through September 2013

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	($31,163,287)	$133,960,556	$34,103,968	$1,947,419	$138,848,656
Financial	$38,900,996	NA	$93,163,353	NA	$132,064,349
Total	$7,737,709	$133,960,556	$127,267,321	$1,947,419	$270,913,005

Table 13-9 lists the monthly FTR profits in 2013 by organization type.

Table 13-9 Monthly FTR profits by organization type: January through September 2013

	Organization Type			
Month	Physical	Self Scheduled Physical FTRs	Financial	Total
Jan	$4,433,798	$24,630,019	$13,640,158	$42,703,975
Feb	$14,090,796	$20,676,306	$16,980,941	$51,748,044
Mar	($9,498,908)	$15,149,289	$4,849,731	$10,500,113
Apr	($12,666,550)	$6,571,358	$2,187,796	($3,907,396)
May	($3,242,261)	$14,590,963	$12,513,107	$23,861,810
Jun	$1,557,793	$12,289,397	$14,357,719	$28,204,910
Jul	$9,677,398	$20,442,580	$33,133,249	$63,253,226
Aug	($11,149,377)	$6,876,920	$3,987,989	($284,468)
Sep	$9,737,992	$14,681,142	$30,413,658	$54,832,792
Total	$2,940,681	$135,907,975	$132,064,349	$270,913,005

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-10 Monthly Balance of Planning Period FTR Auction revenue: January through September 2013

			Class Type			
Monthly Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-13	Obligations	Buy bids	$42,552	$4,558,023	$3,371,362	$7,971,937
		Sell offers	$106,975	$2,609,123	$1,599,772	$4,315,870
	Options	Buy bids	$0	$237,321	$153,334	$390,655
		Sell offers	$0	$1,133,641	$1,206,317	$2,339,958
Feb-13	Obligations	Buy bids	$176,565	$3,587,647	$2,468,155	$6,232,366
		Sell offers	$401,600	$1,782,016	$1,097,066	$3,280,682
	Options	Buy bids	$5,100	$99,651	$128,731	$233,482
		Sell offers	$0	$861,109	$904,603	$1,765,712
Mar-13	Obligations	Buy bids	$189,939	$4,040,854	$3,035,268	$7,266,060
		Sell offers	$61,862	$2,221,264	$1,434,875	$3,718,001
	Options	Buy bids	$16,526	$229,272	$95,137	$340,935
		Sell offers	$0	$1,242,062	$1,381,010	$2,623,072
Apr-13	Obligations	Buy bids	($27,848)	$3,384,641	$2,231,023	$5,587,816
		Sell offers	$414,627	$1,703,707	$1,085,350	$3,203,684
	Options	Buy bids	$46,767	$236,939	$92,241	$375,947
		Sell offers	$0	$816,642	$702,628	$1,519,270
May-13	Obligations	Buy bids	$22,637	$2,501,391	$1,418,753	$3,942,781
		Sell offers	$210,649	$1,133,878	$524,793	$1,869,320
	Options	Buy bids	$0	$146,702	$55,903	$202,605
		Sell offers	$441	$739,219	$602,794	$1,342,454
Jun-13	Obligations	Buy bids	$258,896	$12,840,102	$8,210,854	$21,309,852
		Sell offers	$6,203,476	$4,763,316	$2,821,569	$13,788,360
	Options	Buy bids	$1,937	$527,792	$270,176	$799,905
		Sell offers	$0	$4,338,954	$2,862,300	$7,201,254
Jul-13	Obligations	Buy bids	$510,314	$9,102,951	$4,353,703	$13,966,968
		Sell offers	$93,068	$5,789,068	$4,745,346	$10,627,482
	Options	Buy bids	$4,131	$627,541	$557,307	$1,188,979
		Sell offers	$0	$3,737,741	$3,401,595	$7,139,335
Aug-13	Obligations	Buy bids	$865,368	$8,730,071	$6,036,457	$15,631,896
		Sell offers	$80,061	$5,495,491	$4,455,681	$10,031,232
	Options	Buy bids	$2,361	$533,585	$446,817	$982,762
		Sell offers	$0	$2,977,768	$2,590,004	$5,567,772
Sep-13	Obligations	Buy bids	$528,800	$8,147,903	$5,670,300	$14,347,003
		Sell offers	$219,616	$4,804,814	$3,795,424	$8,819,854
	Options	Buy bids	$633	$617,446	$628,494	$1,246,573
		Sell offers	$0	$3,184,129	$2,500,854	$5,684,983
2012/2013*	Obligations	Buy bids	$67,116	$76,349,386	$43,832,157	$120,248,659
		Sell offers	$4,731,328	$40,127,400	$18,982,130	$63,840,858
	Options	Buy bids	$152,160	$4,512,768	$2,793,076	$7,458,004
		Sell offers	$313,760	$22,240,204	$17,444,010	$39,997,974
	Total		($4,825,812)	$18,494,550	$10,199,092	$23,867,830
2013/2014**	Obligations	Buy bids	$2,163,379	$38,821,027	$24,271,313	$65,255,719
		Sell offers	$6,596,220	$20,852,688	$15,818,020	$43,266,929
	Options	Buy bids	$159,285	$6,291,340	$4,425,694	$10,876,319
		Sell offers	$0	$14,238,592	$11,354,752	$25,593,344
	Total		($4,273,556)	$10,021,086	$1,524,235	$7,271,765

* Shows Twelve Months; ** Shows four months ended 30-Sep-2013 for 2013/2014

Table 13-10 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, type and class type for January through September 2013. The Monthly Balance of Planning Period FTR Auction netted $7.3 million in revenue, with buyers paying $76.1 million and sellers receiving $68.9 million for the first four months of the 2013 to 2014 planning period. For the first four months of the 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auction netted $11.9 million.

Figure 13-5 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period through September. The top 10 positive revenue producing FTR sources accounted for $29.9 million of the total revenue of $0.7 million paid in the auction, they also comprised 5.1 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$10.8 million of revenue and constituted 1.4 percent of all FTRs bought in the auction.

Figure 13-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014 through September

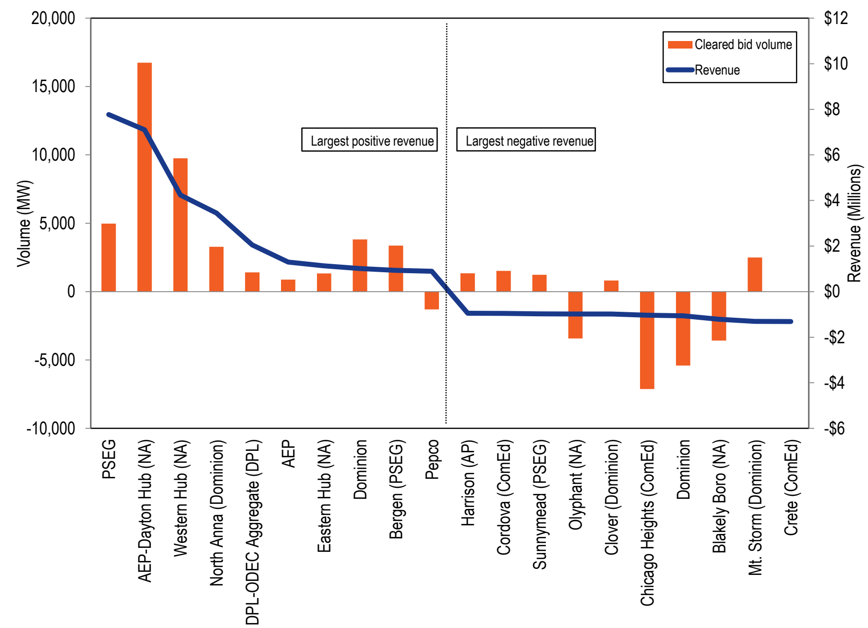


Figure 13-6 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period through September. The top 10 positive revenue producing FTR sources accounted for $30.3 million of the total revenue of $23.9 million paid in the auction, they also comprised 3.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$11.1 million of revenue and constituted 0.5 percent of all FTRs bought in the auction.

Figure 13-6 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014 through September

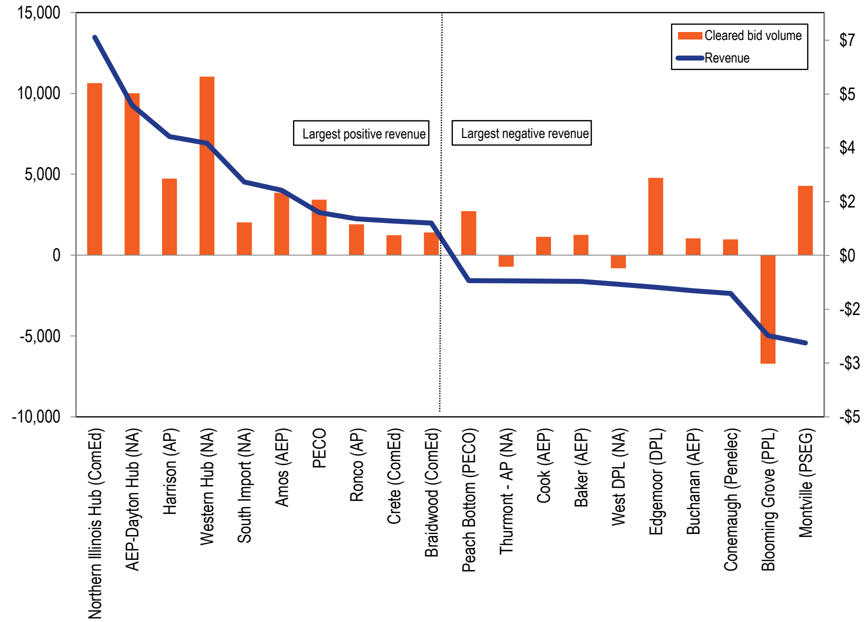
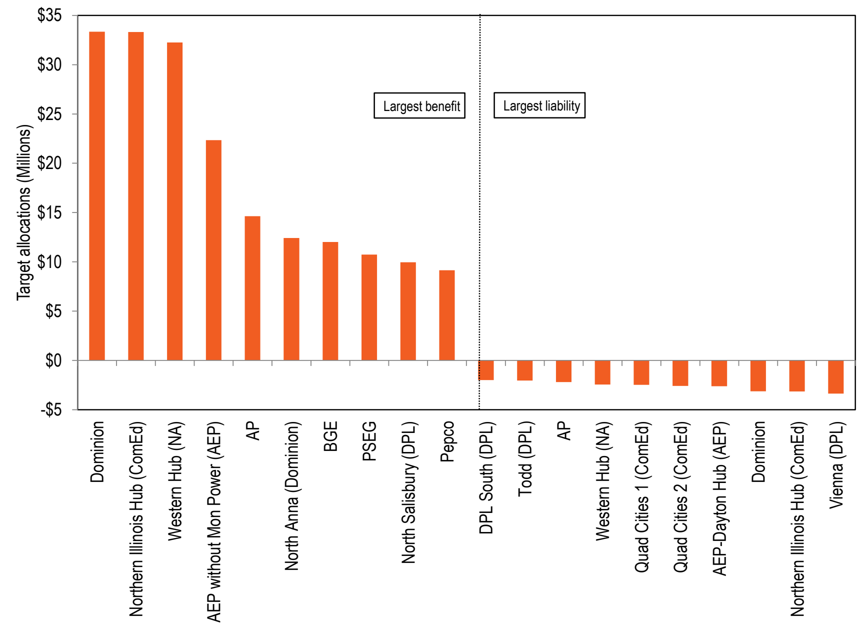


Figure 13-7 Ten largest positive and negative FTR target allocations summed by sink: 2013 to 2014 planning period through September 30, 2013

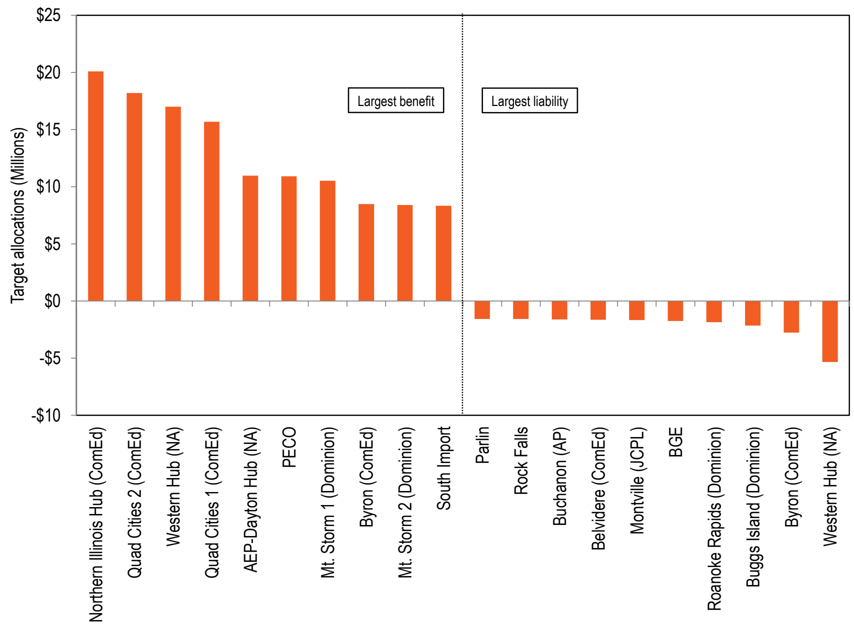


FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2013 to 2014 planning period through September 30, 2013. Figure 13-7 shows the ten largest positive and negative FTR target allocations, summed by sink, for the 2013 to 2014 planning period. The top 10 sinks that produced financial benefit accounted for 18.4 percent of total positive target allocations during the 2013 to 2014 planning period with the Dominion zone accounting for 3.2 percent of all positive target allocations. The top 10 sinks that created liability accounted for 8.9 percent of total negative target allocations with Vienna accounting for 1.2 percent of all negative target allocations.

Figure 13-8 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2013 to 2014 planning period. The top 10 sources with a positive target allocation accounted for 12.4 percent of total positive target allocations with the Northern Illinois Hub accounting for 1.9 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 7.5 percent of all negative target allocations, with the Western Hub accounting for 1.8 percent.

Figure 13-8 Ten largest positive and negative FTR target allocations summed by source: 2013 to 2014 planning period through September 30, 2013



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load in a constrained area pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. That is why load, which pays for the transmission capability, receives ARRs to offset congestion in the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in constrained areas receives the congestion price and all load in constrained areas pays the congestion price. As a result, load congestion payments are greater than the congestion-related payments to generation.[11] This overpayment by load is the source of the congestion revenue to pay holders of ARRs and FTRs. In general, FTR revenue adequacy exists when the sum of congestion credits is equal to or greater than the sum of congestion across the positively valued FTRs. If PJM allocated FTRs equal to the transmission capability into constrained areas, FTR payouts would equal the sum of congestion.

Revenue adequacy must be distinguished from the adequacy of FTRs as an offset against total congestion. Revenue adequacy is a narrower concept that compares total congestion revenues to the total target allocations across the specific paths for which FTRs were available and purchased. A path specific target allocation is not a guarantee of payment. The adequacy of FTRs as an offset against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs offset the actual, total congestion across all paths paid by market participants, regardless of the availability or purchase of FTRs.

FTRs are paid each month from congestion revenues, both day ahead and balancing, FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2011 to 2012 planning period, FTRs were not fully funded and thus an uplift charge was collected.

FTR revenues are primarily comprised of hourly congestion revenue, from the day ahead and balancing markets, and unallocated congestion charges.[12] FTR revenues also include ARR excess which is the difference between ARR target allocations and FTR auction revenues. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets

11 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *MMU Technical Reference for PJM Markets*, at "Financial Transmission and Auction Revenue Rights."

12 Hourly congestion revenues may be negative.

forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 13-11 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO whose operating limits are respected by PJM.[13] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G) and Consolidated Edison Company of New York (Con Edison) resulted in no payment of congestion charges to Con Edison in the 2013 to 2014 planning period.[14,15]

FTRs were paid at 77.3 percent of the target allocation level for the first four months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $614.0 million of FTR revenues during the 2012 to 2013 planning period, and $799.6 million during the 2011 to 2012 planning period, a 23.2 percent decrease. For the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion and the Northern Illinois Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were Vienna and the Western Hub.

Table 13-11 presents the PJM FTR revenue detail for the 2012 to 2013 and first four months of the 2013 to 2014 planning period.

13 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx>. (Accessed March 13, 2012)

14 111 FERC ¶ 61,228 (2005).

15 See the *2012 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "Con Edison and PSE&G Wheeling Contracts" and Appendix E, "Interchange Transactions" at Table E-2, "Con Edison and PSE&G wheel settlements data: 2012."

Table 13-11 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014 through September 2013

Accounting Element	2012/2013	2013/2014*
ARR information		
ARR target allocations	$587.0	$175.0
FTR auction revenue	$653.6	$197.5
ARR excess	$66.7	$22.5
FTR targets		
FTR target allocations	$906.8	$372.4
Adjustments:		
Adjustments to FTR target allocations	($1.0)	$0.4
Total FTR targets	$905.8	$372.0
FTR revenues		
ARR excess	$66.7	$22.5
Competing uses	$0.1	$0.0
Congestion		
Net Negative Congestion (enter as negative)	($90.6)	($26.1)
Hourly congestion revenue	$668.4	$284.0
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	$41.1	$2.2
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	$0.0	$0.0
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	($0.0)	$0.0
Total FTR revenues	$603.4	$278.2
Excess revenues distributed to other months	$0.0	$0.0
Net Negative Congestion charged to DA Operating Reserves	$12.1	$9.2
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$614.0	$287.4
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$614.0	$287.4
Remaining deficiency	$291.8	$84.6

* Shows four months ended 30-Sep-13

Unallocated Congestion Charges

When congestion revenue at the end of an hour is negative, the hourly target allocations in that hour are set to zero, and there is a congestion liability for that hour. At the end of the month, if excess ARR revenue and excess congestion from other hours and months are not adequate to offset the sum of these hourly differences, Day-Ahead Operating Reserves are charged the unallocated congestion charges so that the total congestion for the month is not less than zero. This charge is applied retroactively at the end of the month as additional Day-Ahead Operating Reserves charges and is never credited back to Day-Ahead Operating Reserves in the case of excess congestion. This means that within an hour, the congestion dollars collected from load were less than the congestion dollars paid to generation and there was not enough excess during the month to pay the difference. From 2010 through May 31, 2012, these charges were only made three times, for a total of $7.3 million. However, in the 2012 to 2013 planning period these charges were made in five months for a total of $12.1 million in just one planning period. For the first four months of the 2013 to 2014 planning period the unallocated congestion charges were $9.2 million.

Table 13-12 shows the monthly unallocated congestion charges made to Day-Ahead Operating Reserves for the 2012 to 2013 planning period. Months with no unallocated congestion are excluded from the table.[16]

Table 13-12 Unallocated congestion charges: Planning period 2012 to 2013 and first four month of 2013 and 2014

Period	Charge
Oct-12	$794,752
Dec-12	$193,429
Jan-13	$5,233,445
Mar-13	$701,303
May-13	$5,210,739
Jun-13	$2,828,660
Sep-13	$6,411,602
2012/2013	$12,133,668
2013/2014	$9,240,262

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and are defined to be the revenue required to compensate FTR holders for congestion on those specific paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 13-13 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies.

The total row in Table 13-13 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months.

Table 13-13 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2012 to 2013 and 2013 to 2014 through September 30, 2013

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-12	$58.5	$62.9	92.9%	$58.5	93.0%	($4.4)
Jul-12	$71.3	$80.0	88.9%	$71.3	88.9%	($8.8)
Aug-12	$54.1	$55.4	97.1%	$54.1	97.3%	($1.3)
Sep-12	$38.7	$82.5	46.7%	$38.7	46.8%	($43.8)
Oct-12	$24.3	$58.2	41.8%	$25.1	42.7%	($33.1)
Nov-12	$52.0	$59.6	87.2%	$52.0	87.3%	($7.5)
Dec-12	$36.3	$50.1	72.2%	$36.5	72.5%	($13.6)
Jan-13	$63.4	$120.3	53.4%	$68.6	56.5%	($51.7)
Feb-13	$77.2	$128.1	60.5%	$77.2	60.2%	($50.9)
Mar-13	$51.7	$70.7	73.2%	$52.4	74.2%	($18.2)
Apr-13	$32.7	$47.4	69.4%	$32.7	69.0%	($14.7)
May-13	$41.8	$90.7	46.1%	$47.0	51.9%	($43.7)
Summary for Planning Period 2012 to 2013						
Total	$601.9	$905.8		$614.0	67.8%	($291.8)
Jun-13	$61.3	$81.9	74.7%	$64.1	78.2%	($17.8)
Jul-13	$113.5	$128.3	88.3%	$113.5	88.5%	($14.74)
Aug-13	$43.1	$45.8	94.0%	$43.1	94.0%	($2.74)
Sep-13	$43.1	$116.0	52.0%	$66.7	57.5%	($49.28)
Summary for Planning Period 2013 to 2014						
Total	$260.9	$372.0		$287.4	77.3%	($84.6)

Figure 13-9 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through September 2013. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 13-9 also shows the payout ratio after distributing excess revenue across months

16 See Section 4, "Operating Reserves" at "Operating Reserve Charges" for the impact of Unallocated Congestion Charges on Operating Reserve rates.

within the planning period as well as any unallocated congestion charges. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. Unallocated congestion charges are charged to Day-Ahead Operating Reserves when there is negative congestion within a month. The payout ratios for months in the 2012 to 2013 planning period may change if excess revenue is collected in the remainder of the planning period.

Figure 13-9 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through September 2013

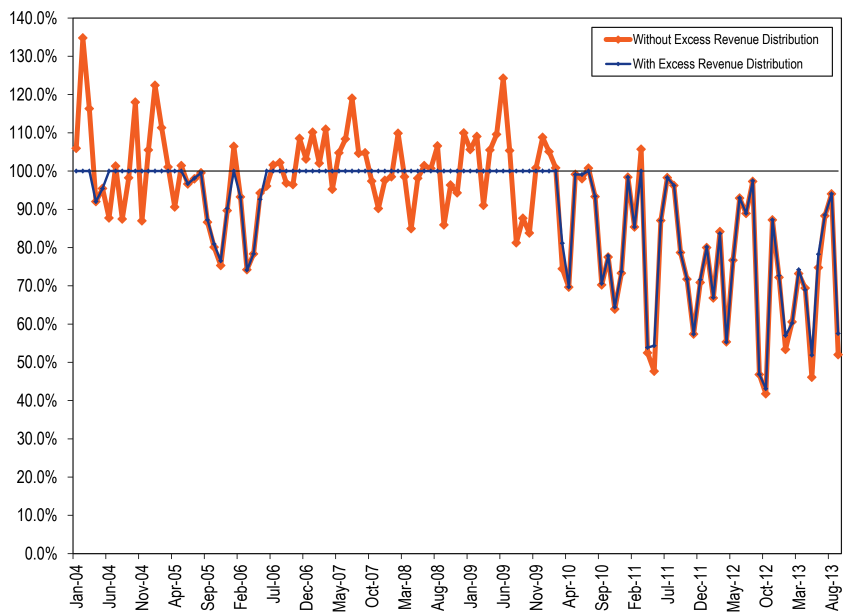


Table 13-14 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves.

Table 13-14 PJM Reported FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	77.3%

*2013/2014 Through 30-Sep-13

FTR Uplift Charge

At the end of the planning period, an uplift charge is applied to FTR holders. This charge is to cover the net of the monthly deficiencies in the target allocations calculated for individual participants. An individual participant's uplift charge is a pro-rata charge, to cover this deficiency, based on their net target allocation with respect to the total net target allocation of all participants with net positive target allocations for the planning period. Participants pay an uplift charge that is a ratio of their share of net positive target allocations to the total net positive target allocations.

The uplift charge is only applied to, and calculated from, members with a net positive target allocation at the end of the planning period. Members with a net negative target allocation have their year-end target allocation set to zero for all uplift calculations. Since participants in the FTR market with net positive target allocations are paying the uplift charge to fully fund FTRs, their payout ratio cannot be 100 percent. The end of planning period payout ratio is calculated as the participant's target allocations minus the uplift charge applied to them divided by their target allocations. The calculations of uplift are structured so that, at the end of the planning period, every participant in the FTR market with a positive net target allocation receives payments based on the same payout ratio. At the end of the planning period and the end of a given month no payout ratio is actually applied to a participant's target allocations. The payout ratio is simply used as a reporting mechanism to demonstrate the amount of revenue available to pay target allocations and represent the percentage of target allocations a participant with a net positive portfolio has been paid for the planning period. However, this same calculation is not accurate when calculating a single month's payout ratio as currently reported, where the calculation of available revenue is not the same.

The total planning period target allocation deficiency is the sum of the monthly deficiencies throughout the planning period. The monthly deficiency is the difference in the net target allocation of all participants and the total revenue collected for that month. The total revenue paid to FTR holders is based on the hourly congestion revenue collected, which includes hourly M2M, wheel payments and unallocated congestion credits.

Table 13-15 provides a demonstration of how the FTR uplift charge is calculated. In this example it is important to note that the sum of the net positive target allocations is $32 and the total monthly deficiency is $10. The uplift charge is structured so that those with higher target allocations pay more of the deficit, which ultimately impacts their net payout. Also, in this example, and in the PJM settlement process, the monthly payout ratio varies for all participants, but the uplift charge is structured so that once the uplift charge is applied the end of planning period payout ratio is the same for all participants.

For the 2012 to 2013 planning period, the total deficiency was $291.8 million. The top ten participants with the highest target allocations paid 53.6 percent of the total deficiency for the planning period. All of the uplift money is collected from individual participants, and distributed so that every participant experiences the same payout ratio. This means that some participants subsidize others and receive less payout from their FTRs after the uplift is applied, while others receive a subsidy and get a higher payout after the uplift is applied. In this example, participants 1 and 5 are paid less after the uplift charge is applied, while participants 3 and 4 are paid more.

Table 13-15 End of planning period FTR uplift charge example

Participant	Net Target Allocation	Total Monthly Payment	Monthly Deficiency	Uplift Charge	Net Payout	Monthly Payout Ratio	EOPP Payout Ratio
1	$10.00	$8.00	$2.00	$3.13	$6.88	80.0%	68.8%
2	($4.00)	$0.00	$0.00	$0.00	($4.00)	100.0%	100.0%
3	$15.00	$10.00	$5.00	$4.69	$10.31	66.7%	68.8%
4	$3.00	$1.00	$2.00	$0.94	$2.06	33.3%	68.8%
5	$4.00	$3.00	$1.00	$1.25	$2.75	75.0%	68.8%
Total	$28.00	$22.00	$10.00	$10.00	$18.00		

Revenue Adequacy Issues and Solutions

PJM Reported Payout Ratio

The payout ratios shown above in Table 13-14 reflect the PJM reported payout ratios for each month of the planning period. These reported payout ratios equal congestion revenue divided by the sum of the net positive and net negative target allocations for each hour of the month. This does not correctly measure the payout ratio actually received by positive target allocation FTR holders in the month, but provides an estimate of the ratio based on the approach to end of planning period calculations, including cross subsidies.

The payout ratio is intended to measure the proportion of the target allocation received by the holders of FTRs with positive target allocations in a month. In fact, the actual monthly payout ratio includes the net negative target allocations as a source of funding for FTRs with net positive target allocations in an hour. Revenue from FTRs with net negative target allocations in an hour are included with congestion revenue when funding FTRs with net positive target allocations.[17] Also included in this revenue is any M2M charge or credit for the month and any excess ARR revenues for the month. The revenue and net target allocations are then summed over the month to calculate the monthly payout ratio. There is no payout ratio applied on a monthly basis, each participant receives a different share of the available revenue based on availability, it is simply used as a reporting mechanism. At the end of a given month, a participant's FTR payments are a proportion of the congestion credits collected, based on the participant's share of the total monthly target

17 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012), p. 50

allocation. The payout ratio is only used and calculated at the end of the planning period after uplift is applied to each participant. The actual monthly payout ratio received by FTR holders equals congestion revenue plus the net negative target allocations divided by the net positive target allocations for each hour. The actual payout ratio received by the holders of positive target allocation FTRs, reported on a monthly basis, is greater than reported by PJM.

Table 13-16 shows the PJM reported and actual monthly payout ratio for the 2012 to 2013 planning period. In September the PJM reported payout ratio is 3.4 percentage points below the actual payout ratio. On a month to month basis, the payout ratio currently reported by PJM does not take into account all sources of revenue available to pay FTR holders. This provides a slightly overstated level of underfunding on a monthly basis.

Table 13-16 PJM Reported and Actual Monthly Payout Ratios: Calendar year 2013

	Reported Monthly Payout Ratio	Actual Monthly Payout Ratio
Jan-13	57.0%	59.9%
Feb-13	60.3%	62.5%
Mar-13	74.2%	75.5%
Apr-13	68.9%	70.8%
May-13	51.9%	54.2%
Jun-13	78.3%	79.5%
Jul-13	88.8%	89.3%
Aug-13	94.1%	94.7%
Sep-13	57.5%	60.9%

Netting Target Allocations within Portfolios

Currently FTR target allocations are netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions.

The current method requires those with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy.

For example, a participant has $200 of positive target allocation FTRs and $100 of negative target allocation FTRs and the payout ratio is 80 percent. Under the current method, the positive and negative positions are first netted to $100 and then the payout ratio is applied. In this example, the holder of the portfolio would receive 80 percent of $100, or $80.

The correct method would first apply the payout ratio to FTRs with positive target allocations and then net FTRs with negative target allocations. In the example, the 80 percent payout ratio would first be applied to the positive target allocation FTRs, 80 percent of $200 is $160. Then the negative target allocation FTRs would be netted against the positive target allocation FTRs, $160 minus $100, so that the holder of the portfolio would receive $60.

In fact, if done correctly, the payout ratio would also change, although the total net payments made to or from participants would not change. The sum of all positive and negative target allocations is the same in both methods. The net result of this change would be that holders of portfolios with smaller shares of negative target allocation FTRs would no longer subsidize holders of portfolios with larger shares of negative target allocation FTRs.

Under the current system all participants with a net positive target allocation in a month are paid a payout ratio based on each participant's net portfolio position. The correct approach would calculate payouts to FTRs with positive target allocations, without netting in an hour. This would treat all FTRs the same, regardless of a participant's portfolio. This approach would also eliminate the requirement that participants with larger shares of positive target allocation FTRs subsidize participants with larger shares of negative target allocation FTRs.

Elimination of portfolio netting should also be applied to the end of planning period FTR uplift calculation. With this approach, negative target allocations would not offset positive target allocations at the end of the planning period when allocating uplift. The FTR uplift charge would be based on participants' share of the total positive target allocations paid for the planning period.

Table 13-17 shows an example of the effects of calculating FTR payouts on a per FTR basis rather than the current method of portfolio netting for four hypothetical organizations for an example hour. The positive and negative TA columns show the total positive and negative target allocations, calculated separately, for each organization. The percent negative target allocations is the share of the portfolio which is negative target allocation FTRs. The net TA is the net of the positive and negative target allocations for the given hour. The FTR netting payout column shows what a participant would see on their bill, including payout ratio adjustments, under the current method. The per FTR payout column shows what a participant would see on their bill, including payout ratio adjustments, if FTR target allocations were done correctly.

This table shows the effects of a per FTR target allocation calculation on individual participants. The total payout does not change, but the allocation across individual participants does.

The largest change in payout is for participants 1 and 2. Participant 1, who has a large proportion of FTRs with negative target allocations, receives less payment. Participant 2, who has no negative target allocations, receives more payment.

Table 13-17 Example of FTR payouts from portfolio netting and without portfolio netting

Participant	Positive TA	Negative TA	Percent Negative TA	Net TA	FTR Netting Payout (Current)	No Netting Payout (Proposed)	Percent Change
1	$60.00	($40.00)	66.7%	$20.00	$8.33	($3.33)	(140.0%)
2	$30.00	$0.00	0.0%	$30.00	$12.50	$18.33	46.7%
3	$90.00	($20.00)	22.2%	$70.00	$29.17	$35.00	20.0%
4	$0.00	($5.00)	100.0%	($5.00)	($5.00)	($5.00)	0.0%
Total	$180.00	($65.00)	0.0%	$115.00	$45.00	$45.00	0.0%

Table 13-18 shows the total value for the 2012 to 2013 and first month of the 2013 to 2014 planning periods of FTRs with positive and negative target allocations. The Net Positive Target Allocation column shows the value of all portfolios with an hourly net positive value after negative target allocation FTRs are netted against positive target allocation FTRs. The Net Negative Target Allocation column shows the value of all portfolios with an hourly net negative value after negative target allocation FTRs are netted against positive target allocation FTRs. The Per FTR Positive Allocation column shows the total value of the hourly positive target allocation FTRs without netting. The Per Negative Allocation column shows the total value of the hourly negative target allocation FTRs without netting.

The Reported Payout Ratio column is the monthly payout ratio as currently reported by PJM, calculated as total revenue divided by the sum of the net positive and net negative target allocations. The No Netting FTR Payout Ratio column is the payout ratio that participants with positive target allocations would receive if FTR payouts were calculated without portfolio netting, calculated by dividing the total revenue minus the per FTR negative target allocation by the per FTR positive target allocations. The total revenue available to fund the holders of positive target allocation FTRs is calculated by adding any negative target allocations to the congestion credits for that month.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio for the 2012 to 2013 planning period would have been 84.5 percent instead of the reported 67.8 percent and the payout ratio for the first four months of the 2013 to 2014 planning period would have been 89.4 percent instead of 77.3 percent.

Table 13-18 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 2012 to 2013 and 2013 to 2014

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jan-13	$129,096,732	($8,682,957)	$233,783,161	($113,347,680)	$68,617,681	57.0%	77.8%
Feb-13	$135,702,271	($7,613,234)	$259,657,461	($131,557,526)	$77,154,565	60.3%	80.4%
Mar-13	$74,421,312	($3,760,700)	$146,552,085	($75,878,638)	$52,428,118	74.2%	87.6%
Apr-13	$50,520,958	($3,090,289)	$108,760,047	($61,325,460)	$32,698,909	68.9%	86.5%
May-13	$95,352,565	($4,678,790)	$190,798,195	($100,110,478)	$47,015,169	51.9%	77.1%
Jun-13	$86,723,727	($4,836,912)	$164,066,220	($82,101,063)	$64,060,468	78.3%	89.1%
Jul-13	$134,302,957	($6,017,378)	$255,724,128	($127,113,708)	$113,548,567	88.8%	94.1%
Aug-13	$51,545,380	($5,741,003)	$104,601,365	($58,796,985)	$43,059,687	94.1%	97.4%
Sep-13	$126,168,822	($10,172,695)	$279,972,757	($163,977,565)	$66,719,631	57.5%	82.4%
2012/2013 Total	$992,878,752	($86,061,137)	$1,897,830,880	($990,471,801)	$614,014,377	67.7%	84.5%
2013/2014 Total	$398,740,885	($26,767,987)	$804,364,470	($431,989,320)	$287,388,353	77.3%	89.4%

Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocation FTRs are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

A counter flow FTR is profitable if the hourly negative target allocation is smaller than the hourly auction payment they received. A prevailing flow FTR is profitable if the hourly positive target allocation is larger than the auction payment they made.

For a prevailing flow FTR, the target allocation would be subject to a reduced payout ratio, while a counter flow FTR holder would not be subject to the reduced payout ratio. The profitability of the prevailing flow FTRs is affected by the payout ratio while the profitability of the counter flow FTRs is not affected by the payout ratio.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. This increased payout ratio would apply only to negative target allocations associated with counter flow FTRs.

Table 13-19 provides an example of how the counter flow adjustment method would impact a two FTR system. In this example there is $15 of total congestion revenue available, corresponding to a reported payout ratio of 75 percent and a monthly actual payout ratio of 87.5 percent. In the example, the profit before and after underfunding can be seen in addition to the profit after underfunding with the counter flow adjustment made. As illustrated, a counter flow FTR's profit does not change when underfunding is applied, whereas a prevailing flow FTR's profit decreases. Applying the counter flow adjustment distributes the underfunding penalty evenly to both prevailing and counter flow FTR holders.

Table 13-19 Example implementation of counter flow adjustment method

	Prevailing A-B 10MW	Counter C-D 10MW
Auction Cost	$50.00	($30.00)
Target Allocation	$40.00	($20.00)
Payout	$30.00	($20.00)
Profit without underfunding	($10.00)	$10.00
Profit after underfunding	($20.00)	$10.00
Payout for Positive TA	$35.00	($20.00)
Profit for Positive TA	($15.00)	$10.00
Payout after CF Adjustment	$36.67	($21.67)
Profit after CF Adjustment	($13.33)	$8.33
Profit Difference	$1.67	($1.67)

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio for the first four months of the 2013 to 2014 planning period from the reported 77.2 percent to 92.3 percent.

Figure 13-10 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through September 2013.

Table 13-20 Counter flow FTR payout ratio adjustment impacts

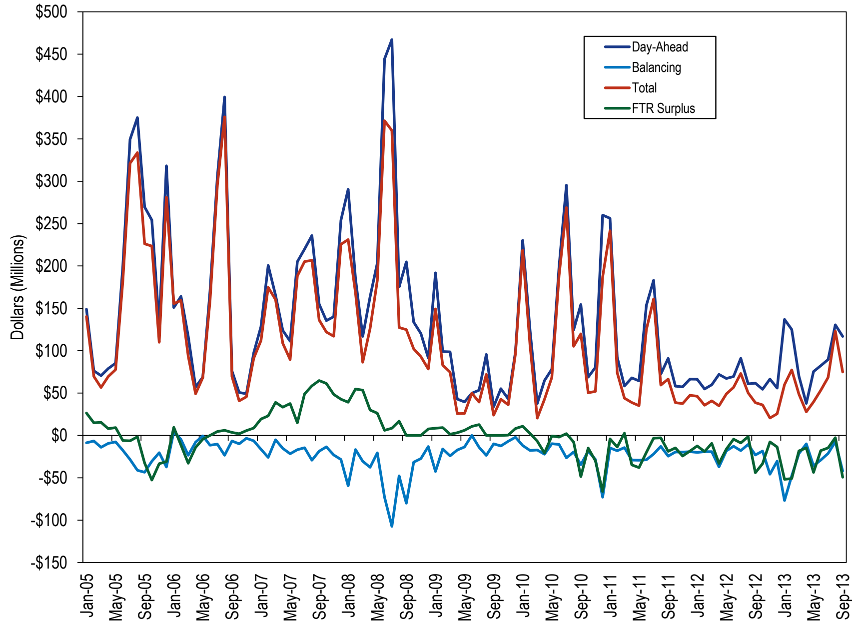
	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Counterflow Payout Ratio	Adjusted Counter Flow Revenue Available
Jan-13	$233,783,161	($113,347,680)	$120,435,482	$68,617,681	57.0%	$181,965,360	83.4%	$194,865,402
Feb-13	$259,657,461	($131,557,526)	$128,099,935	$77,154,565	60.2%	$208,712,090	85.4%	$221,784,584
Mar-13	$146,552,085	($75,878,638)	$70,673,447	$52,428,118	74.2%	$128,306,756	90.8%	$133,040,564
Apr-13	$108,760,047	($61,325,460)	$47,434,587	$32,698,909	68.9%	$94,024,369	90.2%	$98,077,747
May-13	$190,798,195	($100,110,478)	$90,687,717	$47,015,169	51.8%	$147,125,648	82.9%	$158,212,887
Jun-13	$164,066,220	($82,101,063)	$81,965,157	$64,060,468	78.2%	$146,161,531	91.9%	$150,770,760
Jul-13	$255,724,128	($127,113,708)	$128,610,420	$113,548,567	88.3%	$240,662,275	95.6%	$244,362,737
Aug-13	$104,601,365	($58,796,985)	$45,804,380	$43,059,687	94.0%	$101,856,672	98.1%	$102,592,928
Sep-13	$279,972,757	($163,977,565)	$115,995,192	$66,719,631	57.5%	$230,697,196	87.3%	$244,550,556
Total 2012/2013	$1,897,830,880	($990,471,801)	$907,359,079	$614,537,096	67.7%	$1,605,008,896	88.6%	$1,681,443,058
Total 2013/2014	$804,364,470	($431,989,320)	$372,375,150	$287,388,353	77.2%	$719,377,673	92.3%	$742,276,981

* Reported payout ratios may vary due to rounding differences when netting

Table 13-20 shows the monthly positive, negative and total target allocations.[18] Table 13-20 also shows the total congestion revenue available to fund FTRs, as well as the total revenue available to fund positive target allocation FTR holders on a per FTR basis and on a per FTR basis with counter flow payout adjustments. Implementing this change to the payout ratio for counter flow FTRs would result in an additional $22.9 million (27.1 percent of underfunding) in revenue available to fund positive target allocations for the first four months of the 2013 to 2014 planning period.

18 Reported payout ratio may differ between Table 13-18 and Table 13-20 due to rounding differences when netting target allocations and considering each FTR individually.

Figure 13-10 FTR Surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through September 2013



Up-to-Congestion Impacts on FTR Funding

In order to study the impacts of UTCs on FTR funding, the Day-Ahead Market was rerun by PJM with and without UTC transactions for five days in May 2013.

Analysis of PJM's data from these reruns of the May 2, 4, 22, 23, 27 of 2013 day ahead market with and without UTC bids supports the hypothesis that UTC transactions contribute significantly to FTR underfunding.[19] The data indicate that removal of UTCs significantly improves FTR funding for each of the five days. FTR underfunding is a measure of the difference between total FTR target allocations and total congestion dollars available to fund FTRs. When FTR target allocations are greater than total congestion dollars, FTRs are considered underfunded, as FTR obligations are less than congestion dollars available. When FTR target allocations are less than congestion dollars available, FTRs are considered fully funded and there is a surplus of congestion dollars. Table 13-21 shows, for each study day, the actual FTR underfunding for the day, the FTR underfunding after the removal of UTC, the change in FTR underfunding caused by the removal of UTC from PJM's day ahead market model.

Analysis of PJM's data shows that for the five days studied, the removal of UTCs changed FTR funding relative to target allocations from a deficit of -$4.1 million to a net surplus of $537 thousand, a gain in funding relative to target allocations of $4.7 million. The magnitude of the effect depends on the day, but the results indicate that the removal of UTC takes PJM FTRs from a state of underfunding to a state of surplus in the five days studied.

Analysis of PJM's data from these reruns shows that removal of UTCs significantly decreases FTR target allocations on the five studied days. Target allocations are a function of FTR MW and the difference in the day ahead CLMP at the FTR source and sink bus. The removal of UTC bids significantly decreased day ahead congestion and CLMPs. This reduction in congestion and CLMPs reduced the target allocations of all FTRs. Table 13-21 shows, for each study day, the actual target allocations, the target allocations after the removal of UTC, and the change in target allocations caused by the removal of UTC from PJM's day ahead market model. PJM's data show that removing UTCs reduced the target allocations over the five study days by $8.5 million, or 52 percent.

19 These conclusions are based on the five days selected by PJM and the system conditions on those days.

Table 13-21 Changes in target allocations in PJM results by day: May 2, 4, 22, 23, 27 of 2013

Date	Actual Target Allocations	No UTC Target Allocations	Difference in Target Allocations	Change in Target Allocations
2-May-13	$1,361,464	$1,060,874	($300,590)	(22.1%)
4-May-13	$934,840	$137,589	($797,250)	(85.3%)
22-May-13	$7,002,555	$2,605,640	($4,396,915)	(62.8%)
23-May-13	$6,125,559	$3,779,988	($2,345,571)	(38.3%)
27-May-13	$817,088	$196,132	($620,956)	(76.0%)
Total	$16,241,505	$7,780,223	($8,461,282)	(52.1%)

The PJM data show that the inclusion of UTCs significantly increased total day ahead congestion compared to the case where there were no UTCs in the market, and significantly increased (made balancing charges more negative) the real time balancing congestion adjustment offset to day ahead total congestion compared to the case with no UTCs.

Table 13-22 Changes in FTR funding in PJM results by day: May 2, 4, 22, 23, 27 of 2013

	Actual Underfunding	No UTC Underfunding	Difference in Underfunding	Change in Underfunding
2-May-13	($456,443)	($424,086)	$32,358	(7.1%)
4-May-13	($305,854)	$124,345	$430,200	(140.7%)
22-May-13	($1,758,420)	$1,175,869	$2,934,289	(166.9%)
23-May-13	($1,874,367)	($631,962)	$1,242,406	(66.3%)
27-May-13	($38,119)	($24,031)	$14,089	(37.0%)
Total	($4,433,204)	$220,137	$4,653,341	(105.0%)

Up-to-Congestion Transactions and FTR Forfeitures

Currently there is no FTR forfeiture rule implemented for Up-to-Congestion Transactions (UTCs). A proposed tariff change that would apply the FTR forfeiture rule to UTCs is pending at FERC.[20] The FTR forfeiture rule should be applied to UTCs in the same way it is applied to INCs and DECs. The goal of the rule is to prevent the use of virtual bids (generally unprofitable virtual bids) to increase Day-Ahead congestion on an FTR path in order to increase the value of the FTRs. The proposed penalty should be the same as it is for the INC and DEC rule, the forfeiture of any profits from FTRs whose value is affected by a UTC with the same owner.

However the rule submitted by PJM, currently under review by FERC, would not be consistent with the application of the current forfeiture rule for INCs and DECs. Under PJM's proposed method the simple net dfax of the UTC transaction is the only consideration for forfeiture, representing the contract path of the UTC transaction. Under this method, the net dfax is the sink dfax of the UTC minus the source dfax of the UTC. The net dfax alone cannot be used as an indication of helping or hurting a constraint, rather, the direction of the constraint must also be considered. In addition, the PJM method only considers UTC transactions whose net dfax is positive. This logic not only passes transactions that should fail the forfeiture test, but fails transactions that should pass the forfeiture test.

PJM's logic also does not hold when one of the points of the UTC is far from the constraint. In this case, one side of the UTC would have a dfax of zero, indicating no connection to the constraint being considered. If a point of the UTC transaction has no connection to the constraint, there can be no power flow directly between the two UTC points, so the simple net dfax, which relies on the contract path of the UTC, cannot logically be used in this case to indicate whether a UTC is eligible for forfeiture. Under the IMM method this UTC would be treated as an INC or DEC and follow the same rules as the current INC/DEC FTR forfeiture rule.

Figure 13-11 shows an example of the two proposed FTR forfeiture rules for UTC transactions. In both cases the net dfax of the UTC is taken. Under the PJM method the net dfax of the UTC is calculated by subtracting the dfax of the sink bus A (0.2) from the dfax of the source bus B (0.5) to get a net dfax of -0.3. If this net dfax value is greater than 0.75 the UTC is subject to forfeiture. Under the IMM method, the net dfax is calculated by subtracting the dfax of sink A (0.2) from the dfax of source bus B (0.5) to get a net dfax of 0.3. This net dfax is then compared to the withdrawal point with the largest impact on the constraint. The IMM method compares the net UTC dfax to a withdrawal because the UTC is a net injection. In this example, the net dfax is 0.3 and it is

20 *See* FERC Docket No. ER13-1654.

compared to the largest withdrawal dfax at C (-0.5). The absolute value of the difference is calculated from these two points to determine if the UTC fails the FTR forfeiture rule. In this case, the absolute value of the difference is the dfax of bus C (-0.5) minus the net UTC dfax (0.3) for a total impact of 0.8, which is over the 0.75 threshold for the FTR forfeiture rule. The result is that this UTC fails the FTR forfeiture rule. The IMM proposes to apply the same rules to UTC transactions as is applied to INCs and DECs, treat the UTC as equivalent to an INC or a DEC depending on its net impact. A UTC transaction is essentially a paired INC/DEC, it has a net impact on the flow across a constraint, as an INC or DEC does. While total system power balance is maintained by a UTC, local flows may change based on the UTC's net impact on a constraint. The IMM method captures this impact.

Figure 13-11 Illustration of UTC FTR forfeiture rule

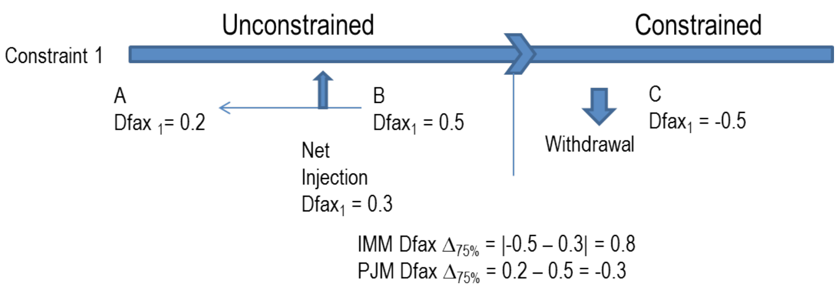
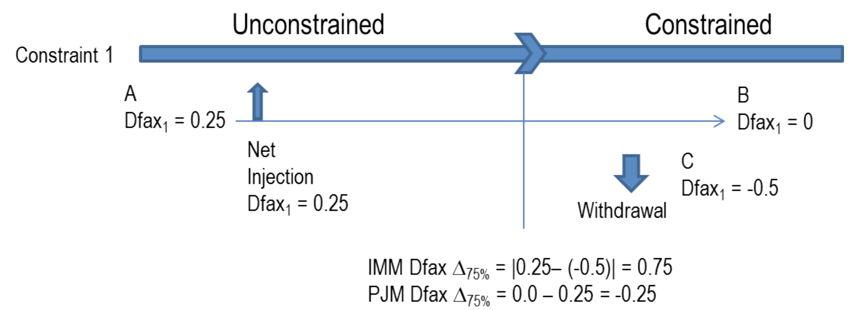


Figure 13-12 demonstrates where the assumption of contract path for UTCs in PJM's method does not hold with actual system conditions when either the source or sink of the UTC does not have any impact on the constraint being considered. In this case, the UTC is effectively an INC or a DEC relative to the constraint, as the other end of the UTC has no impact on the constraint. However, the PJM approach would not treat the UTC as an INC or DEC, despite the effective absence of the other end of the UTC. This is a flawed result.

As demonstrated in Figure 13-12, the UTC is no different than in INC on the constraint be considered. In the PJM method this UTC would pass the FTR forfeiture rule. The net dfax would be calculated as the dfax of bus B (0) minus the dfax of bus A (0.25) for a net dfax of -0.25, with no comparison to any withdrawal bus. Since the dfax is negative, it would pass the PJM FTR forfeiture rule. Under the IMM's method, the net dfax is calculated as an injection with a dfax of 0.25, and then the absolute value of the difference is calculated between that injection and the dfax of the largest withdrawal on the constraint. In this example that is bus C, with a dfax of -0.5. The result is an absolute value of the dfax difference of 0.75, meaning that this UTC fails the FTR forfeiture test.

Figure 13-12 Illustration of UTC FTR Forfeiture rule with one point far from constraint



The MMU recommends that the FTR forfeiture rule be applied to UTCs in the same way it is applied to INCs and DECs.

Auction Revenue Rights

ARRs are financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences determined in the Annual FTR Auction.[21] These price differences are based on the bid prices of participants in the Annual FTR Auction. The auction clears the set of feasible FTR bids which produce the highest net revenue. ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences and the associated level of revenue sufficiency.[22]

21 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.
22 For a more complete explanation, see the *2012 State of the Market Report for PJM*, Volume II, Section 12, "FTRs."

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods through the 2013 to 2014 planning period, all eligible market participants were allocated ARRs.

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[23] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self-scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. In the first four months of the 2013 to 2014 planning period, there were 25,157 MW of ARRs associated with approximately $125,800 of revenue.

Table 13-23 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2012 and September 2013.

Table 13-23 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2012, through September 30, 2013

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2012/2013 (12 months)	2013/2014 (4 months)*	2012/2013 (12 months)	2013/2014 (4 months)*
AECO	581	597	$3.0	$2.3
AEP	4,656	1,617	$58.9	$14.2
AP	3,518	876	$84.3	$19.0
ATSI	5,314	2,437	$8.3	$2.6
BGE	3,203	2,056	$37.3	$14.6
ComEd	11,824	5,114	$170.9	$21.1
DAY	589	164	$0.9	$0.3
DEOK	2,979	2,126	$1.6	$2.9
DLCO	2,708	2,996	$19.1	$6.7
DPL	1,989	1,071	$11.5	$7.4
Dominion	0	5	$0.0	$0.1
EKPC	NA	0	NA	$0.0
JCPL	1,373	710	6	$3.3
Met-Ed	1,107	393	9	$3.1
PECO	3,416	494	23	$4.1
PENELEC	920	408	8	$4.6
PPL	3,198	1,395	21	$5.3
PSEG	2,313	1,044	17	$10.1
Pepco	3,073	1,474	21	$4.2
RECO	67	179	0	$0.1
Total	52,825	25,157	$499.8	$125.8

* Through 30-Sep-2013

23 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

Residual ARRs

Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs are available if additional transmission system capability is added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs are effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and exist until the end of the planning period. For the following planning period, any residual ARRs are available as ARRs in the annual ARR allocation. Stage 1 ARR holders have a priority right to ARRs. Residual ARRs are a separate product from incremental ARRs.

Effective August 1, 2012, as ordered by FERC in Docket No. EL12-50-000, in addition to new transmission, residual ARRs are now available for eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility becomes available during the modeled year. These residual ARRs are determined the month before the effective date, are only available on paths prorated in Stage 1 of the Annual ARR Allocation and are allocated automatically to participants. Residual ARRs are effective for single, whole months and cannot be self scheduled. ARR target allocations are based on the clearing prices from FTR obligations in the effective monthly auction, may not exceed zonal Network Services Peak Load or Firm Transmission Reservation Levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation.

Table 13-24 shows the Residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 13-24 Residual ARR allocation volume and target allocation January 2013 through September 2013

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-13	6,773.0	1,547.2	22.8%	$488,251
Feb-13	1,567.4	1,493.7	95.3%	$229,856
Mar-13	5,351.2	1,522.7	28.5%	$286,193
Apr-13	5,452.1	1,608.9	29.5%	$325,662
May-13	6,054.7	1,647.4	27.2%	$282,425
Jun-13	10,864.1	1,272.7	11.7%	$667,291
Jul-13	10,936.9	1,323.7	12.1%	$714,675
Aug-13	9,357.2	767.2	8.2%	$236,885
Sep-13	1,855.0	402.9	21.7%	$85,884
Total	58,211.6	11,586.4	19.9%	$3,317,123

Market Performance

Revenue

As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as an offset to total congestion. Revenue adequacy is a narrower concept that compares the revenues available to ARR holders to the value of ARRs as determined in the Annual FTR Auction. ARRs have been revenue adequate for every auction to date. Customers that self schedule ARRs as FTRs have the same revenue adequacy characteristics as all other FTRs.

The adequacy of ARRs as an offset to total congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs offset market participants' actual, total congestion into their zone. Customers that self schedule ARRs as FTRs provide the same offset to congestion as all other FTRs.

ARR holders received a projected $626.7 million in credits from the FTR auctions during the 2012 to 2013 planning period, with a projected average hourly ARR credit of $0.66 per MW. During the comparable 2011 to 2012 planning period, ARR holders received $1,055.9 million in ARR credits with an average hourly ARR credit of $1.06 per MW.

Table 13-25 lists projected ARR target allocations from the Annual ARR Allocation, and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 and the 2013 to 2014 planning periods.

Table 13-25 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

	2012/2013	2013/2014
Total FTR auction net revenue	$626.7	$559.0
Annual FTR Auction net revenue	$602.9	$558.4
Monthly Balance of Planning Period FTR Auction net revenue*	$23.9	$0.6
ARR target allocations	$570.5	$503.4
ARR credits	$570.5	$503.4
Surplus auction revenue	$56.2	$55.6
ARR payout ratio	100%	100%
FTR payout ratio*	67.8%	77.3%

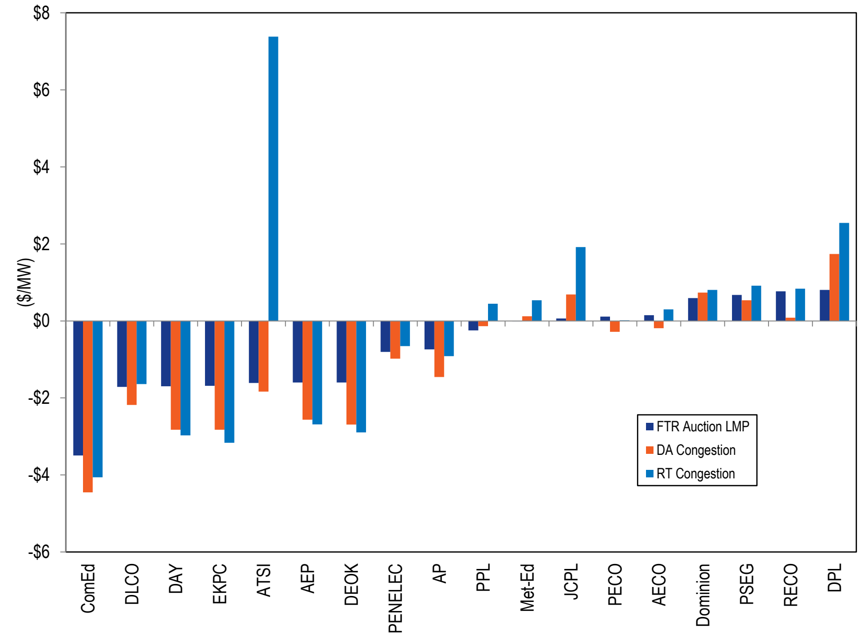
* Shows twelve months for 2012/2013 and four months for 2013/2014.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 13-13 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2013 to 2014 planning period through September 30, 2013. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 13-13 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2013 to 2014 through September 30, 2013



Effectiveness of ARRs as an Offset to Congestion

One measure of the effectiveness of ARRs as an offset to congestion is a comparison of the revenue received by the holders of ARRs and the congestion paid by the holders of ARRs in both the Day-Ahead Energy Market and the Balancing Energy Market. The revenue which serves as an offset for ARR holders comes from the FTR auctions while the revenue for FTR holders is provided by the congestion payments from the Day-Ahead Energy Market and the balancing energy market. During the first ten months of the 2012 to 2013 planning period, the total revenues received by the holders of all ARRs and FTRs offset 92.6 percent of the total congestion costs within PJM.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market is presented by control zone in Table 13-26. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[24] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the ARR credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self-scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self-scheduled FTR MW) and the cleared price for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and may be less than the target allocation. The FTR payout ratio was 77.3 percent of the target allocation for the 2013 to 2014 planning period through September 30, 2013. The target allocation is not a guarantee of payment nor does it reflect congestion incurred on a particular FTR path. The target allocation is used to set a cap on path specific FTR payouts.

The Congestion column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the balancing energy market and includes only the congestion costs incurred by the organizations that hold ARRs or self-scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Table 13-26 ARR and self-scheduled FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period through September 30, 2013[25]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$4.1	$0.0	$4.1	$0.4	$3.7	>100%
AEP	$32.1	$17.8	$49.9	$3.7	$51.5	>100%
APS	$38.9	$7.9	$46.8	($0.1)	$49.2	>100%
ATSI	$5.8	$0.1	$5.9	$0.4	$5.5	>100%
BGE	$29.3	$0.5	$29.8	$2.1	$27.8	>100%
ComEd	$74.6	$0.0	$74.6	$3.5	$71.1	>100%
DAY	$4.0	($0.0)	$4.0	($0.1)	$4.1	>100%
DEOK	$3.7	$0.5	$4.2	($0.1)	$4.5	>100%
DLCO	$1.9	($0.0)	$1.8	$0.0	$1.8	>100%
Dominion	$7.5	$21.6	$29.1	($0.0)	$35.5	>100%
DPL	$17.1	$1.6	$18.7	$1.1	$18.1	>100%
EKPC	$0.6	$0.0	$0.6	$0.2	$0.5	>100%
External	$2.6	($0.0)	$2.6	$0.4	$2.2	>100%
JCPL	$6.6	$0.0	$6.6	$1.3	$5.3	>100%
Met-Ed	$6.7	$0.1	$6.8	$0.5	$6.3	>100%
PECO	$22.3	$0.0	$22.3	$0.2	$22.2	>100%
PENELEC	$12.2	($0.0)	$12.2	$0.6	$11.6	>100%
Pepco	$16.0	$1.0	$17.1	$2.6	$14.8	>100%
PPL	$9.4	$0.1	$9.5	$1.4	$8.2	>100%
PSEG	$37.2	$1.1	$38.3	$1.7	$36.9	>100%
RECO	$0.1	$0.0	$0.1	$0.1	$0.0	>100%
Total	$333.0	$56.2	$389.2	$19.5	$386.2	>100%

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 13-27 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the balancing energy market for the 2012 to 2013 planning period. This compares the total offset provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the cleared price of the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions, and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout

24 For Table 13-26 through Table 13-28, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The "External" Control Zone includes all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

25 The "External" zone was labeled as "PJM" in previous State of the Market Reports. The name was changed to "External" to clarify that this component of congestion is accrued on energy flows between external buses and PJM interfaces.

ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 77.3 percent of the target allocation for the 2013 to 2014 planning period through September 30, 2013. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR offset is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the Balancing Energy Market in each control zone.[26] The last column shows the difference between the total ARR and FTR offset and the congestion cost for each control zone.

26 The total zonal congestion numbers were calculated as of November 6, 2013 and may change as a result of continued PJM billing updates.

Table 13-27 ARR and FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period through September 30, 2013

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$4.1	$0.6	$4.3	$0.4	$3.9	($3.6)	9.0%
AEP	$83.4	$41.6	$104.4	$20.6	$45.3	($24.7)	45.5%
APS	$63.5	$12.3	$32.4	$43.5	$30.1	$13.5	>100%
ATSI	$5.9	$13.8	($0.1)	$19.7	($22.6)	$42.4	>100%
BGE	$30.5	$15.7	$30.2	$16.0	$19.8	($3.8)	80.8%
ComEd	$84.2	$42.3	$60.9	$65.6	$67.9	($2.3)	96.6%
DAY	$4.0	$2.3	$4.0	$2.4	$1.6	$0.7	>100%
DEOK	$4.4	$3.4	$4.7	$3.1	($2.6)	$5.6	>100%
DLCO	$2.1	$0.1	$0.9	$1.3	$0.8	$0.5	>100%
Dominion	$94.9	$52.0	$134.1	$12.8	$32.1	($19.3)	39.8%
DPL	$19.3	$21.4	$14.8	$25.9	$13.9	$11.9	>100%
EKPC	$2.1	$0.1	$2.9	($0.7)	($1.1)	$0.4	0.0%
External	$3.2	($0.9)	$1.9	$0.4	($0.5)	$0.8	>100%
JCPL	$6.6	$13.5	$7.3	$12.8	$12.5	$0.3	>100%
Met-Ed	$6.9	$6.7	$8.3	$5.2	$2.2	$3.0	>100%
PECO	$22.4	$3.9	$17.9	$8.4	($2.8)	$11.2	>100%
PENELEC	$12.1	$16.7	$43.7	($14.9)	$15.1	($30.0)	0.0%
Pepco	$19.3	$23.8	$71.6	($28.5)	$25.4	($53.8)	0.0%
PPL	$9.5	$7.5	$1.6	$15.5	$0.9	$14.5	>100%
PSEG	$39.4	$13.9	$44.4	$9.0	$13.4	($4.4)	66.9%
RECO	$0.1	($0.3)	($0.8)	$0.6	$0.9	($0.3)	65.2%
Total	$518.0	$290.7	$589.5	$219.2	$256.3	($37.2)	85.5%

Table 13-28 shows the total offset due to ARRs and FTRs for the entire 2012 to 2013 planning period and the 2013 to 2014 planning period through September 30, 2013.

Table 13-28 ARR and FTR congestion hedging (in millions): Planning periods 2012 to 2013 and 2013 to 2014 through September 30, 2013[27]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2012/2013	$577.2	$610.3	$654.1	$533.4	$575.9	($42.5)	92.6%
2013/2014	$518.0	$290.7	$589.5	$219.2	$256.3	($37.2)	85.5%

27 The FTR credits do not include after-the-fact adjustments. For the 2013 to 2014 planning period, the ARR credits were the total credits allocated to all ARR of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the planning period and the portion of Annual FTR Auction revenue distributed to the entire planning period.