State of the Market Report for PJM

Volume 2: Detailed Analysis

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 *2012 State of the Market Report for PJM.*

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).

TABLE OF CONTENTS

TABLES

SECTION 1 INTRODUCTION 1

SECTION 2 ENERGY MARKET 49

SECTION 6 NET REVENUE 189

FIGURES

Introduction

2012 In Review

The state of the PJM markets in 2012 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 2012. 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 in 2011 continued in 2012.

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.

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.

Both coal and natural gas prices decreased in 2012 compared to 2011. PJM LMPs were substantially lower. The load-weighted average LMP was $35.23 per MWh, 23.3 percent lower in 2012 than in 2011, the lowest average annual energy prices since 2002.

The results of the energy market dynamics in 2012 were generally positive for new gas fired combined cycle units. New combined cycle units continued to be cheaper than existing coal units. The result of the changes in gas prices compared to coal prices was that the fuel cost to produce a MWh from a new entrant combined cycle unit was below that of a new entrant coal plant for February through June but greater for January and July through December. However, the fuel cost of a new entrant combined cycle unit was below that of existing coal plants given that nearly all coal plants in PJM are 20 years or older. The combination of lower energy prices, mixed gas prices and lower coal prices resulted in lower energy revenues for the new entrant CC unit in all but four zones and lower energy net revenues for the new entrant CT and coal unit in all zones in 2012. With lower capacity prices, net revenues from energy and capacity markets decreased in 2012 for a new entrant combined cycle energy, a new entrant combustion turbine and a new entrant coal plant in PJM in 2012.

Markets need accurate and understandable information about fundamental market parameters in order to function effectively. For example, the markets need better information about unit retirements in order to permit new entrants to address reliability issues. 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.

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 and the continued inclusion of inferior demand side products that also suppress market prices.

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 Background

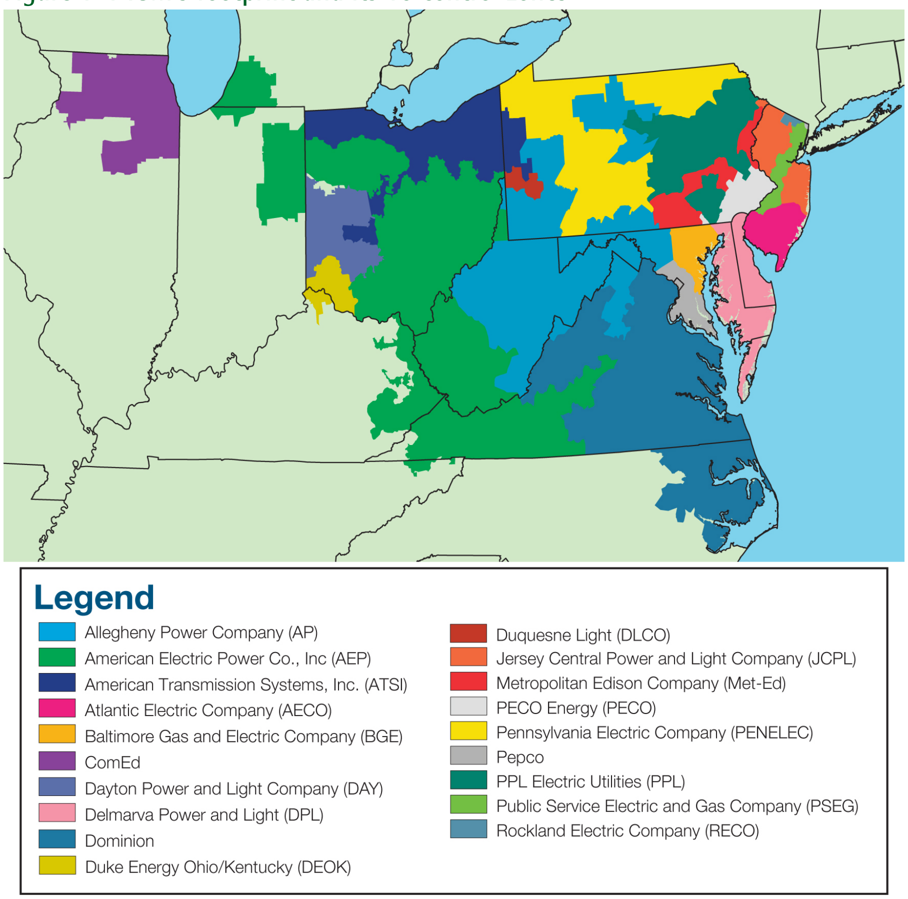
The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2012, had installed generating capacity of 181,990 megawatts (MW) and about 800 market buyers, sellers and traders of electricity[1] in a region including more than 60 million people[2] in all or parts of Delaware, Illinois, Indiana,

1 See PJM's "Company Overview," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.

2 *Id.*

Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[3] In 2012, PJM had total billings of $29.18 billion, down from $35.89 billion in 2011. 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.

Figure 1-1 PJM's footprint and its 19 control zones[4]



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.[5,6]

On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone.

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2012, 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

3 See the Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2012.

4 On January 1, 2012, the Duke Energy Ohio/Kentucky (DEOK) Control Zone joined the PJM footprint.

5 See also Appendix B, "PJM Market Milestones."

6 Analysis of 2012 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. 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 2012, see Appendix A, "PJM Geography."

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 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 2012:

Table 1-1 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 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1240 with a minimum of 931 and a maximum of 1657 in 2012.
- 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.[7] 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.[8]

Table 1-2 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction (BRA), for every planning year for which a BRA has been run to date. For almost all auctions held from 2007 to the present, the PJM region failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.[9]
- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the PMSS, which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which a BRA has been run to date. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[10]
- 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.

7 OATT Attachment M.

8 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.

9 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

10 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.

Table 1-3 The Regulation Market results were not competitive for the first three quarters and were indeterminate for the fourth quarter[11]

	January through September, 2012		October through December, 2012	
Market Element	Evaluation	Market Design	Evaluation	Market Design
Market Structure	Not Competitive		Not Competitive	
Participant Behavior	Competitive		Competitive	
Market Performance	Not Competitive	Flawed	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 43 percent of the hours in 2012.[12]

- Participant behavior in the Regulation Market was evaluated as competitive for the year 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 not competitive for the first three quarters, despite competitive participant behavior, because prior changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.13

- Market performance was evaluated as indeterminate for the fourth quarter, 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 remain to be decided by FERC and because there is not yet enough information on performance.

- Market design was evaluated as flawed for the first three quarters because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there were additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

- Market design was evaluated as indeterminate for the fourth quarter, 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. It is too early to reach a definitive conclusion about the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information about actual implementation of the design.

Table 1-4 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 Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 22 percent of the hours in 2012.

- 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 prices that reflect marginal costs.

- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

11 As Table 1-3 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the market rules, in particular the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

12 These TPS results reflect MMU estimates for the period between May 6 and July 21, 2012, when the TPS test was not correctly applied by PJM.

13 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

Table 1-5 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), about 12 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.

Table 1-6 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The 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.
- 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 effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism. Nonetheless there is a growing issue with FTR revenue sufficiency.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[14] 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.[15]

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

14 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).

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

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.

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.[16] The MMU has direct, confidential access to the FERC.[17] The MMU may also refer matters to the attention of State commissions.[18]

The MMU monitors market behavior for violations of FERC Market Rules.[19] 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,[20] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[21] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[22]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[23] 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[24] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[25] 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).[26] 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.[27]

The MMU also reviews operational parameter limits included with unit offers,[28] evaluates compliance with the requirement to offer into the energy and capacity markets,[29] evaluates the economic basis for unit retirement requests[30] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[31]

16 OATT Attachment M § IV.

17 OATT Attachment M § IV.K.3.

18 OATT Attachment M § IV.H.

19 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.").

20 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.

21 OATT Attachment M § II(h-1).

22 OATT Attachment M § IV.C.

23 OATT Attachment M § IV.I.1.

24 *Id.*

25 *Id.*

26 See OATT Attachment M–Appendix § II.A.

27 OATT Attachment M–Appendix § II.E.

28 OATT Attachment M–Appendix § II.B.

29 OATT Attachment M–Appendix § II.C.

30 OATT Attachment M–Appendix § IV.

31 OATT Attachment M–Appendix § VII.

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.[32] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[33] 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.[34] 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.[35] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[36]

Prioritized Summary Recommendations

Table 1-7 includes a brief description and a priority ranking of the MMU's recommendations.

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.

The reference number links to a detailed description of the recommendation in "Detailed Recommendations."

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

Table 1-7 Prioritized summary recommendations

Priority	Section	Description	Reference Number
Medium	2 - Energy Market	Eliminate FMU and AU adders	2-1
Medium	2 - Energy Market	The definition of maximum emergency status for generating units should apply at all times rather than just during Maximum Emergency Events	2-2
Medium	3 - Operating Reserve	Improve classification of operating reserve credits to ensure correct allocation.	3-1
Medium	3 - Operating Reserve	The allocation of operating reserve charges should be carefully reexamined.	3-2
Medium	3 - Operating Reserve	Require all up-to congestion transactions to pay day-ahead and balancing O.R. charges.	3-3
High	3 - Operating Reserve	Energy LOC should be based on the schedule on which units are scheduled/committed, not the higher of cost or price.	3-4
Medium	3 - Operating Reserve	Energy LOC paid to CTs and diesels scheduled in DA and not called in RT should include the avoided no load and startup costs.	3-5
Medium	3 - Operating Reserve	Energy LOC paid to CTs and diesels scheduled in DA and not called in RT should not use the DA LMP in the calculation.	3-6
Medium	3 - Operating Reserve	Energy LOC should be calculated using entire offer curve, not a single point on the curve.	3-7
Low	3 - Operating Reserve	PJM should analyze why some CTs and diesels scheduled in DA are not being called in RT while being economic.	3-8
Low	3 - Operating Reserve	Include LOC for CTs and diesels scheduled in DA not called in RT in calculation of Perfect Dispatch.	3-9
Low	3 - Operating Reserve	Compensate wind units on the lesser of desired output, forecasted output, or Capacity Injection Rights.	3-10
Medium	3 - Operating Reserve	The total cost of providing reactive support should be categorized and allocated as reactive services.	3-11
Low	3 - Operating Reserve	Reactive services credits should be calculated on segments which include all hours for which unit provides reactive service.	3-12
High	4 - Capacity	Eliminate the Short-Term Resource Procurement Target (2.5 percent demand offset).	4-1
High	4 - Capacity	Modify definition of Demand Side resources; eliminate Limited and Extended Summer DR so DR has same year round capacity obligation as generation.	4-2
Low	4 - Capacity	PJM should procure the maximum amount of Annual and Extended Summer capacity resources available during an RPM auction, without impacting the clearing price.	4-3
Low	4 - Capacity	Address barriers to entry in capacity market; capture the uncertainty and risk in cost of new entry when developing capacity market demand curve.	4-4
Low	4 - Capacity	Redefine the test for determining modeled Locational Deliverability Areas in RPM, including reliability analysis of units at risk.	4-5
Low	4 - Capacity	Modifications to existing resources should not be treated as new resources for purposes of market power related offer caps or MOPR offer floors	4-6
Low	4 - Capacity	Requirement should exist that capacity unit offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.	4-7
Low	4 - Capacity	Define rules for recalling energy output of capacity resources in emergency condition.	4-8
Low	4 - Capacity	Generation capacity resources should be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.	4-9
Medium	4 - Capacity	Unit offer not consistent with DA offer should reflect outage, not offer energy on an emergency basis	4-10
High	4 - Capacity	All generation types should face the same performance incentives.	4-11
High	4 - Capacity	Eliminate OMC outages from use in planning or capacity markets, develop transparent rules for OMC, and review all OMC outage requests carefully.	4-12
Low	4 - Capacity	Eliminate lack of fuel as an acceptable basis for an OMC outage.	4-13
Low	4 - Capacity	Eliminate lack of gas exception during winter for single-fuel, natural gas-fired units.	4-14
Low	4 - Capacity	Unit not capable of fulfilling DA offer should reflect outage, not emergency availability.	4-15
Low	4 - Capacity	Eliminate the exception for units that run less than 50 hours during RPM peak period.	4-16
Low	4 - Capacity	Extend deactivation notification requirement from 90 days to 12 months prior to retirement, and extend duration of PJM and MMU analysis.	4-17
Medium	4 - Capacity	Extend deactivation notification requirement to 6 to 12 months prior to RPM auction.	4-18
Low	4 - Capacity	Emphasize costs in RMR filings; customers should bear incremental costs, generation should bear all other costs.	4-19
High	4 - Capacity	All MOPR projects should be required to use the same basic modeling assumptions.	4-20
High	5 - Demand Response	DR should be classified as an economic program and not an emergency program.	5-1
Medium	5 - Demand Response	Actual meter load data should be provided in order to measure and verify actual demand resource behavior.	5-2
Medium	5 - Demand Response	M & V should reflect compliance. Testing should have limited warning to CSPs.	5-3
Low	5 - Demand Response	Demand resources should be required to provide their nodal location.	5-4
Medium	5 - Demand Response	Compliance rules should be revised to include submittal of hourly load data, and negative values when calculating compliance across hours and registrations.	5-5
Low	5 - Demand Response	Shutdown cost should be defined as the cost to curtail load for a given period that does not vary with the measured reduction.	5-6
Low	5 - Demand Response	Modify the testing program to require verification of test methods and results.	5-7
Medium	5 - Demand Response	Refine baseline methods used to calculate compliance in LM for GLD customers.	5-8
Medium	8 - Interchange Transactions	PJM should permit unlimited spot market imports and exports at all PJM Interfaces.	8-1
Medium	8 - Interchange Transactions	PJM should continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established.	8-2
Medium	8 - Interchange Transactions	Market participants should be required to submit transactions on market paths that reflect the expected actual flow.	8-3
High	8 - Interchange Transactions	PJM and the MMU should perform a comprehensive evaluation of the up-to congestion product and provide a joint report to PJM stakeholders.	8-4
High	8 - Interchange Transactions	During the period of study, up-to congestion transactions should be required to pay a fee in lieu of operating reserve charges.	8-5
Low	8 - Interchange Transactions	Terminate the existing PJM/PEC JOA.	8-6
High	8 - Interchange Transactions	Implement rules to prevent sham scheduling.	8-7
Low	9 - Ancillary Services	Incorporate the three pivotal supplier test in the DASR Market.	9-1
Medium	9 - Ancillary Services	Definition of LOC should be based on the offer schedule accepted in the market.	9-2
High	9 - Ancillary Services	Regulation Market should have consistent implementation of the marginal benefit factor in optimization, pricing and settlement for RegA and RegD.	9-3
Medium	9 - Ancillary Services	Define transparent rules for calculating available Tier 1 synchronized reserve MW and for its use of biasing during any phase of the market solution.	9-4
Low	9 - Ancillary Services	Reevaluate Synchronized Reserve compliance rules.	9-5
Medium	11 - Planning	Projects should be removed from the queue, if they are no longer viable and no longer planning to complete the project.	11-1
High	12 - FTRs	The reported FTR payout ratio should consider negative target allocations as a source of revenue to fund FTRs.	12-1
High	12 - FTRs	Netting of positive and negative target allocations within portfolios should be eliminated.	12-2
High	12 - FTRs	Counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.	12-3
Medium	12 - FTRs	The difference between day ahead and balancing congestion should be reviewed.	12-4

Detailed 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,"[37] 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 *2012 State of the Market Report for PJM*, the MMU makes the following recommendations.

From Section 2, "Energy Market":

- 2-1) 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 significant changes to the scarcity pricing rules in 2012. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.
- 2-2) The MMU recommends that the definition of maximum emergency status for generating units apply at all times rather than just during Maximum Emergency Events.

From Section 3, "Operating Reserve":

- 3-1) The MMU recommends PJM clearly identify and classify all reasons for incurring operating reserves in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The 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.
- 3-2) The MMU recommends that the allocation of operating reserve charges to participants be carefully reexamined to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.
  - 3-3) The MMU recommends, that in the absence of the elimination of the up-to congestion transaction product and the absence of a reexamination of the allocation of all operating reserve charges, PJM should require all up-to congestion transactions to pay day-ahead and balancing operating reserve charges.
- The MMU recommends four modifications to the energy lost opportunity cost calculations.
  - 3-4) 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.
  - 3-5) 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.
  - 3-6) 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.
  - 3-7) The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- 3-8) The MMU recommends PJM initiate an analysis on the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not being called in real time while being economic.
- 3-9) The MMU recommends including the lost opportunity costs paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not called in real time in the calculation of PJM's Perfect Dispatch metric.
- 3-10) The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). In addition, the MMU recommends PJM allow and wind units submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time.

37 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

- 3-11) The MMU recommends the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be equal to the positive difference between total offer (including no load and startup costs) and energy revenues.
- 3-12) The MMU recommends that reactive services credits be calculated on segments which include all hours for which unit provides reactive service. Segments should be the higher of hours needed for reactive support and minimum run time

From Section 4, "Capacity":

- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.
  - 4-1) The MMU recommends that the Short-Term Resource Procurement Target (2.5 percent demand offset) be eliminated.
  - 4-2) The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources provide the same value in the Capacity Market as generation resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources.
  - 4-3) Pending elimination of these DR products, the MMU recommends that PJM procure the maximum amount of Annual and Extended Summer capacity resources available during an RPM auction, without impacting the clearing price. Currently, PJM procures a minimum level of Extended Summer and Annual Resources, but could procure additional MW of these superior products without a change in the clearing price.
  - 4-4) The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM.
  - 4-5) The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.
  - 4-6) The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors.
- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.
  - 4-7) The MMU recommends that there be an explicit requirement that capacity unit offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.
  - 4-8) The MMU recommends that protocols be defined for recalling the energy output of capacity resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details.
- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.
  - 4-9) The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. All revenues should be at risk under the peak hour availability charge.
  - 4-10) The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.
  - 4-11) The MMU recommends that all generation types face the same performance incentives.
- The MMU recommends that the treatment of outages be made consistent with appropriate market incentives.
  - 4-12) The MMU recommends elimination of all Out of Management Control (OMC) outages from use in planning or capacity markets.

MMU recommends that pending elimination of OMC outages, that PJM review all requests for Out of Management Control (OMC) carefully, implement a transparent set of rules governing the designation of outages as OMC and post those guidelines.

- 4-13) The MMU recommends immediate elimination of lack of fuel as an acceptable basis for an OMC outage.
- 4-14) The MMU recommends elimination of the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.
- 4-15) The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.
- 4-16) The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period.

- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.
  - 4-17) The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses.
  - 4-18) The MMU recommends that the notification requirement for deactivations be modified to include required notification of six to twelve months prior to an auction in which the unit will not be offered due to deactivation. The purpose of this deadline is to allow adequate time for potential Capacity Market Sellers to offer new capacity in the auction.
  - 4-19) The MMU recommends that treatment of costs in RMR filings be emphasized. Customers should bear all the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Generation owners should bear all other costs.

- 4-20) The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.

From Section 5, "Demand Response":

- 5-1) The MMU recommends that the DR program be classified as an economic program and not an emergency program.
- 5-2) The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.
- 5-3) The MMU recommends that demand side measurement and verification should be modified to accurately reflect compliance. Increases in load during event hours should not be considered zero response, but should be included for reporting and determining compliance.
- 5-4) 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
- 5-5) 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.
- 5-6) The MMU recommends that shutdown cost should be defined as the cost to curtail load for a given period that does not vary with the measured reduction, or for behind the meter generators, should be equivalent to the start cost defined in Manual 15.
- 5-7) The MMU recommends that the testing program be modified to require verification of test methods and results. Tests should be initiated by PJM without prior scheduling by CSPs, in order to more accurately model demand response during an emergency event.
- 5-8) The MMU recommends refinement of the baseline methods used to calculate compliance in Load Management for GLD customers.

From Section 6, "Net Revenue":

- There are no recommendations in Section 6.

From Section 7, "Environmental and Renewables":

- There are no recommendations in Section 7.

From Section 8, "Interchange Transactions":

- 8-1) PJM and MISO have agreed to allow for unlimited spot market ATC on the NYISO Interface. These modifications are currently being evaluated by PJM. The MMU continues to recommend that PJM permit unlimited spot market imports and exports at all PJM Interfaces.
- 8-2) 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.
- 8-3) 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.
- 8-4) 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.
- 8-5) 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.
- 8-6) 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.
- 8-7) 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.

From Section 9, "Ancillary Services":

- 9-1) The MMU recommends that the TPS test be incorporated in the DASR market.
- 9-2) The MMU recommends that the definition of opportunity cost be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market.
- 9-3) The MMU recommends that the Regulation Market design evaluate and compensate RegA and RegD resources on an equivalent, non-discriminatory basis. This requires the consistent implementation of the marginal benefits factor in optimization, pricing and settlement.
- 9-4) The MMU recommends that PJM define explicit and transparent rules for calculating available Tier 1 synchronized reserve MW and for its use of biasing during any phase of the market solution. The MMU recommends that PJM publish these rules in Manual 11: Energy and Ancillary Services Market Operations, and associate each instance of biasing with a rule.
- 9-5) The MMU recommends that the rules for compliance with calls to respond to actual spinning events be reevaluated.

From Section 10, "Congestion and Marginal Losses":

- There are no recommendations in Section 10.

From Section 11, "Planning":

- 11-1) The MMU recommends that a review process be created to ensure that projects are removed from transmission queues, if they are no longer viable and no longer planning to complete the project.

From Section 12, "FTRs and ARRs":

- 12-1) The MMU recommends that the calculation of the reported payout ratio appropriately include negative target allocations as a source of revenue to fund FTRs, consistent with actual settlement payout.

- 12-2) The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.
- 12-3) The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.
- 12-4) The MMU recommends that the difference between day ahead and balancing congestion be reviewed and modifications implemented where possible. Funding issues that persist as a result of modeling differences should be borne by FTR holders operating in the voluntary FTR market

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 1-8 provides the average price and total revenues paid, by component, for the first nine months of 2011 and 2012.

Table 1-8 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 95.0 percent of the total price per MWh in the first nine months of 2012.

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 Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[43]
- 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.[44]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[45]
- The Black Start component is the average cost per MWh of black start service.[46]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[47]

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 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.

44 OATT Schedule 1A.

45 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.

46 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.

47 OATT Attachments H-13, H-14 and H-15 and Schedule 13.

Table 1-8 Total price per MWh by category and total revenues by category: 2011 and 2012

Category	2011 $/MWh	2012 $/MWh	Percent Change Totals	2011 Percent of Total	2012 Percent of Total
Load Weighted Energy	$45.94	$35.23	(23.3%)	73.4%	72.6%
Capacity	$9.72	$6.05	(37.7%)	15.5%	12.5%
Transmission Service Charges	$4.42	$4.78	8.3%	7.1%	9.9%
Operating Reserves (Uplift)	$0.79	$0.79	0.0%	1.3%	1.6%
Reactive	$0.42	$0.43	3.0%	0.7%	0.9%
PJM Administrative Fees	$0.37	$0.42	15.6%	0.6%	0.9%
Transmission Enhancement Cost Recovery	$0.29	$0.34	17.9%	0.5%	0.7%
Regulation	$0.32	$0.26	(20.2%)	0.5%	0.5%
Transmission Owner (Schedule 1A)	$0.09	$0.08	(11.0%)	0.1%	0.2%
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.05	(10.3%)	0.1%	0.1%
Synchronized Reserves	$0.09	$0.04	(55.2%)	0.1%	0.1%
Black Start	$0.02	$0.03	28.3%	0.0%	0.1%
NERC/RFC	$0.02	$0.02	19.6%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(5.4%)	0.0%	0.0%
Load Response	$0.01	$0.01	43.0%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	(17.1%)	0.0%	0.0%
Non-Synchronized Reserves		$0.00			0.0%
Total	$62.56	$48.55	(22.4%)	100.0%	100.0%

- 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: Calendar years 2001 through 2012[48]

Category	Totals ($/MWh) 2001	Totals ($/MWh) 2002	Totals ($/MWh) 2003	Totals ($/MWh) 2004	Totals ($/MWh) 2005	Totals ($/MWh) 2006	Totals ($/MWh) 2007	Totals ($/MWh) 2008	Totals ($/MWh) 2009	Totals ($/MWh) 2010	Totals ($/MWh) 2011	Totals ($/MWh) 2012
Load Weighted Energy	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$45.94	$35.23
Capacity	$0.32	$0.12	$0.08	$0.09	$0.03	$0.03	$3.97	$8.33	$11.02	$12.15	$9.72	$6.05
Transmission Service Charges	$3.46	$3.37	$3.56	$3.26	$2.68	$3.15	$3.41	$3.65	$4.00	$4.00	$4.42	$4.78
Operating Reserves (Uplift)	$1.07	$0.69	$0.86	$0.93	$0.97	$0.45	$0.63	$0.61	$0.48	$0.79	$0.79	$0.79
Reactive	$0.22	$0.20	$0.24	$0.25	$0.26	$0.29	$0.31	$0.32	$0.36	$0.44	$0.42	$0.43
PJM Administrative Fees	$0.36	$0.43	$0.54	$0.50	$0.38	$0.40	$0.38	$0.24	$0.31	$0.36	$0.37	$0.42
Transmission Enhancement Cost Recovery									$0.09	$0.21	$0.29	$0.34
Regulation	$0.50	$0.42	$0.50	$0.50	$0.79	$0.53	$0.63	$0.70	$0.34	$0.35	$0.32	$0.26
Transmission Owner (Schedule 1A)	$0.08	$0.07	$0.07	$0.11	$0.09	$0.09	$0.09	$0.09	$0.08	$0.09	$0.09	$0.08
Day Ahead Scheduling Reserve (DASR)								$0.00	$0.00	$0.01	$0.05	$0.05
Synchronized Reserves		$0.11	$0.19	$0.16	$0.15	$0.10	$0.11	$0.09	$0.05	$0.06	$0.09	$0.04
Black Start		$0.00	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03
NERC/RFC							$0.01	$0.01	$0.01	$0.02	$0.02	$0.02
RTO Startup and Expansion		$0.04	$0.05	$0.10	$0.37	$0.15	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Load Response	-$0.00	$0.00	$0.02	$0.00	$0.00	$0.03	$0.07	$0.03	$0.00	$0.00	$0.01	$0.01
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Synchronized Reserves												$0.00
Total	$42.66	$37.05	$47.36	$50.25	$69.20	$58.58	$71.30	$85.24	$55.85	$66.85	$62.55	$48.55

48 Data are missing for January of 2002.

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.

Table 1-10 Percentage of total price per MWh by category: Calendar years 2001 through 2012[53]

Category	Percentage of Total Charges 2001	Percentage of Total Charges 2002	Percentage of Total Charges 2003	Percentage of Total Charges 2004	Percentage of Total Charges 2005	Percentage of Total Charges 2006	Percentage of Total Charges 2007	Percentage of Total Charges 2008	Percentage of Total Charges 2009	Percentage of Total Charges 2010	Percentage of Total Charges 2011	Percentage of Total Charges 2012
Load Weighted Energy	85.9%	85.3%	87.1%	88.2%	91.7%	91.1%	86.5%	83.4%	69.9%	72.3%	73.4%	72.6%
Capacity	0.7%	0.3%	0.2%	0.2%	0.0%	0.0%	5.6%	9.8%	19.7%	18.2%	15.5%	12.5%
Transmission Service Charges	8.1%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%	7.1%	9.9%
Operating Reserves (Uplift)	2.5%	1.9%	1.8%	1.8%	1.4%	0.8%	0.9%	0.7%	0.9%	1.2%	1.3%	1.6%
Reactive	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.7%	0.9%
PJM Administrative Fees	0.8%	1.2%	1.1%	1.0%	0.5%	0.7%	0.5%	0.3%	0.5%	0.5%	0.6%	0.9%
Transmission Enhancement Cost Recovery									0.2%	0.3%	0.5%	0.7%
Regulation	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.5%	0.5%	0.5%
Transmssion Owner (Schedule 1A)	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%
Day Ahead Scheduling Reserve (DASR)								0.0%	0.0%	0.0%	0.1%	0.1%
Synchronized Reserves		0.3%	0.4%	0.3%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%
Black Start		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
NERC/RFC							0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion		0.1%	0.1%	0.2%	0.5%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Load Response	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Non-Synchronized Reserves												0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Section Overviews

Overview: Section 2, "Energy Market"

Market Structure

- **Supply.** Average offered supply increased by 4,180, or 2.5 percent, from 169,234 MW in the summer of 2011 to 173,414 MW in the summer of 2012.[54] The increase in offered supply was in part the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) Transmission Zone in the first quarter of 2012 and the integration of the American Transmission Systems, Inc. (ATSI) Transmission Zone in the second quarter of 2011. In 2012, 2,669 MW of new capacity were added to PJM. This new supply was more than offset by the deactivation of 45 units (6,691.9 MW) since January 1, 2012.

- **Demand.** The PJM system peak load for 2012 was 154,344 MW in the HE 1700 on July 17, 2012, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for 2011, which was 158,016 MW in the HE 1700 on July 21, 2011.[55] The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of 2012. The 2012 peak load excluding the DEOK Transmission Zone was 148,984 MW, also occurring on July 17, 2012, HE 1700, a decrease of 9,032 MW, or 5.7 percent, from the 2011 peak load.

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

- **Local Market Structure and Offer Capping.** 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 2012. PJM offer caps units only 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 offer-capped unit hours increased from 0.0 percent in 2011 to 0.6 percent in 2012. In the Real-Time Energy Market offer-capped unit hours increased from 0.9 percent in 2011 to 1.2 percent in 2012.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 133 units eligible for FMU or AU status in at least one month during 2012, 25 units (18.8 percent) were FMUs or AUs for all months, and 25 (18.8 percent) qualified in only one month of 2012.

  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,

53 Data are missing for January of 2002.

54 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.

55 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).

including implementation of the RPM capacity market construct in 2007, and significant 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.

- **Local Market Structure.** In 2012, 11 Control Zones experienced congestion resulting from one or more constraints binding for 100 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.[56]

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. Actual participant behavior support 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.

  In 2012, the unadjusted markup was negative, primarily as a result of competitive behavior by coal units. The unadjusted markup component of LMP was -$1.38 per MWh. The adjusted markup was $.43 per MWh or 1.2 percent of the PJM real-time, load-weighted average LMP of $35.23 per MWh.

  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 2012 increased by 5.4 percent from 2011, from 82,546 MW to 87,011 MW. The PJM average real-time load in 2012 would have decreased by 2.0 percent from 2011, from 82,546 MW to 80,909 MW, if the DEOK and ATSI Transmission Zones were not included in this comparison for the months prior to their integration to PJM.[57]

  PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, increased by 15.6 percent from 2011, from 113,866 MW to 131,612 MW. PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, would have been 8.9 percent higher than in 2011, from 113,866 MW to 124,046 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison. The day-ahead load growth was 188.9 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 2012 increased by 3.4 percent from 2011, from 85,755 MW to 88,708 MW. PJM average real-time generation in 2012 would have decreased by 2.5 percent from 2011, from 85,755 MW to 83,630 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.

  PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, increased by 14.8 percent from 2011, from 117,130 MW to 134,479 MW. PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, would have been 4.7 percent higher than in 2011, from 117,130 MW to 122,599 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison. The day-ahead generation growth was 335.3 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

56 See the *2012 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

57 The ATSI zone was integrated on June 1, 2011. The DEOK zone was integrated on January 1, 2012. The ATSI zone was not included in this comparison for January through May 2011, and January through May 2012. The DEOK zone was not included in this comparison.

- **Generation Fuel Mix.** During 2012, coal units provided 42.1 percent, nuclear units 34.6 percent and gas units 18.8 percent of total generation. Compared to 2011, generation from coal units decreased 7.4 percent, generation from nuclear units increased 4.0 percent, and generation from gas units increased 39.0 percent.

- **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 decreased in 2012 compared to 2011. The system average LMP was 22.7 percent lower in 2012 than in 2011, $33.11 per MWh versus $42.84 per MWh. The load-weighted average LMP was 23.3 percent lower in 2012 than in 2011, $35.23 per MWh versus $45.94 per MWh.

  PJM Day-Ahead Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.9 percent lower in 2012 than in 2011, $32.79 per MWh versus $42.52 per MWh. The load-weighted average LMP was 23.5 percent lower in 2012 than in 2011, $34.55 per MWh versus $45.19 per MWh.[58]

- **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. In 2012, 9.0 percent of real-time load was supplied by bilateral contracts, 23.2 percent by spot market purchase and 67.8 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 1.5 percentage points, reliance on spot supply decreased by 3.4 percentage points and reliance on self-supply increased by 4.9 percentage points. In 2012, 6.7 percent of day-ahead load was supplied by bilateral contracts, 22.3 percent by spot market purchases, and 71.0 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply decreased by 2.1 percentage points, and reliance on self-supply increased by 1.3 percentage points.

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

Scarcity

- **Scarcity Pricing Events in 2012.** PJM did not declare an administrative scarcity event in 2012. PJM's market did not experience any reserve-based shortage events in 2012.

- **Scarcity and High Load Analyses.** There were no reserve shortages in 2012. There were seven high load days and 40 high-load hours in 2012. There were 28 Hot Weather Alerts called in 2012.

Section 2 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in 2012, 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 4,180 MW in the summer of 2012 compared to the summer of 2011, while peak load decreased by 3,672 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in 2012 increased from 2011, from 113,866 MW to 131,612 MW, or 15.6 percent. In the Real-Time Energy Market, average load in 2012 increased from 2011, from 82,546 MW to 87,011 MW, or 5.4 percent. 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 2012 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.[59] 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 2012.

Overview: Section 3, "Operating Reserve"

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges in 2012 were $648.7 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 25.6 percent, the balancing operating reserve charges proportion was 66.4 percent, the reactive services charges proportion was 8.0 percent and the synchronous condensing charges proportion was 0.02 percent.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.2001 per MWh, the balancing operating reserve reliability rates averaged $0.0245, $0.0219 and $0.1154 per MWh for the RTO, Eastern and Western Regions, the balancing operating reserve deviation rates averaged $0.8147,

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

$0.3332 and $0.1265 per MWh for the RTO, Eastern and Western Regions. Lost opportunity cost rate averaged $1.3223 per MWh and canceled resources rate averaged $0.0235 per MWh.

- **Operating Reserve Credits.** Four operating reserve categories accounted for 97.8 percent of all operating reserve credits. Balancing generator operating reserves were 35.1 percent, lost opportunity cost were 29.5 percent, day-ahead generator operating reserves were 25.6 percent and reactive services were 7.6 percent of all credits.

Characteristics of Credits

- **Types of units.** Coal units received 74.3 percent of all day-ahead generator credits and 48.5 percent of all balancing generator credits. Wind units received 94.6 percent of all canceled resources credits. Combustion turbines and diesels received 87.3 percent of the lost opportunity cost credits. Combined cycles and coal units received 80.1 percent of all reactive services credits.

- **Economic – Noneconomic Generation.** In 2012, 84.2 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.9 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In 2012, 83.3 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 5.8 percent by transactions at hubs and 10.9 percent by transactions at interfaces.

- Generators in the Eastern Region paid 11.5 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 49.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 12.3 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 50.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- Generators paid 13.3 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.9 percent of all credits.

Load Response Resource Operating Reserves

- In 2012, 96.4 percent of the total energy revenues for end use customers for providing demand reductions as part of the Economic Load Response Program was paid as economic load response credits. The remaining 3.6 percent was operating reserve credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 22.7 percent of all credits. The top 10 organizations received 81.7 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 3720, balancing operating reserves was 3105 and lost opportunity cost HHI was 4169.

- **Day-Ahead Unit Commitment for Reliability:** On September 13, 2012, PJM increased the number and MWh of units scheduled as must run in the Day-Ahead Energy Market because the units were regularly needed for reliability in real time. PJM identified the need to schedule these units in the Day-Ahead Energy Market after determining that these units were affecting the commitment process for combustion turbines in real time. The increase in day ahead scheduling was intended to reduce the divergence between the scheduled resources in the Day-Ahead Market and the actual resources operating in the Real-Time Energy Market. The addition of units scheduled as must run in the Day-Ahead Energy Market shifted substantial operating reserve credits from the Balancing Energy Market to the Day-Ahead Energy Market. This is significant because day-ahead operating reserve charges and balancing operating reserve charges are allocated differently. FERC accepted proposed revisions to PJM's tariff and operating agreement to change the allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for reliability purposes.

- **Lost Opportunity Cost Credits:** In 2012, lost opportunity cost credits increased by $18.8 million compared to 2011. In 2012, the top three control zones receiving lost opportunity cost credits, AP, ComEd and Dominion combined for 64.4 percent of all lost opportunity cost credits, 60.3 percent of all the day-ahead generation from pool-scheduled combustion turbines and diesels, 65.8 percent of all day-ahead generation not called in real time by PJM from those unit types and 68.5 percent of all 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 2012, lost opportunity cost credits would have been reduced by $60.8 million, or 31.8 percent, if all changes proposed by the MMU had been implemented.
- **Wind Units Lost Opportunity Cost:** In 2012, lost opportunity cost credits paid to wind units would have been reduced by $3.1 million, or 65.6 percent, if all changes proposed by the MMU had been implemented.
- **Black Start and Voltage Support Units:** Certain units located in the AEP zone are relied on for their ALR blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. The MMU raised the issue that such costs should be categorized as black start costs rather than operating reserve charges. This issue was resolved in PJM's tariff and operating agreement filing with FERC.
- **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.
- **Up-to Congestion Transactions:** Up-to congestion transactions do not pay operating reserve charges despite that they affect dispatch and commitment in the Day-Ahead Energy Market. The impact of assigning operating reserve charges to up-to congestion transactions on the payments by other participants would be significant. For example, in 2012, the RTO deviation rate would have been reduced by 59.3 percent if up-to congestion transactions had been included in the calculation of operating reserve charges.

Section 3 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 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.

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 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.

The MMU recommends that the allocation of operating reserve charges to participants be carefully reexamined to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. 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 issue of netting using internal bilateral transactions should be addressed.

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.

Overview: Section 4, "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.[60]

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.[61] 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.[62] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13 and four months, prior to the delivery year. Also effective for the 2012/2013 Delivery Year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[63]

RPM prices are locational and may vary depending on transmission constraints.[64] 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

60 The terms *PJM Region, RTO Region and RTO* are synonymous in the *2011 State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.
61 See 126 FERC ¶ 61,275 (2009) at P 86.
62 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
63 See 126 FERC ¶ 61,275 (2009) at P 88.
64 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.

in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand-side resources and Energy Efficiency resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During 2012, PJM installed capacity resources increased from 178,854.1 MW on January 1 to 181,990.1 on December 31, primarily due to the integration of the Duke Energy Ohio and Kentucky (DEOK) Control Zone into PJM.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2012, 41.8 percent was coal; 28.6 percent was gas; 18.1 percent was nuclear; 6.3 percent was oil; 4.3 percent was hydroelectric; 0.4 percent was solid waste; 0.4 percent was wind, and 0.0 percent was solar.
- **Supply.** Total internal capacity increased 10,070.6 MW from 159,882.7 MW on June 1, 2011, to 169,953.3 MW on June 1, 2012. This increase was the result of the reclassification of the Duquesne resources as internal at the time of the 2012/2013 RPM Base Residual Auction (3,187.2 MW), new generation (785.5 MW), reactivated generation (0.0 MW), net generation capacity modifications (cap mods) (-1,637.3 MW), Demand Resource (DR) modifications (8,028.7 MW), Energy Efficiency (EE) modifications (652.5 MW), the EFORd effect due to lower sell offer EFORds (-944.1 MW), and lower Load Management UCAP conversion factor (-1.9 MW).
- **Demand.** There was a 3,237.4 MW increase in the RPM reliability requirement from 154,251.1 MW on June 1, 2011, to 157,488.5 MW on June 1, 2012. This increase was primarily due to the inclusion of the Duquesne Zone in the preliminary forecast peak load for the 2012/2013 RPM Base Residual Auction. On June 1, 2012, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.9 percent, up slightly from 71.4 percent on June 1, 2011.
- **Market Concentration.** For the 2012/2013, 2013/2014, 2014/2015, and 2015/2016 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2012/2013 RPM First Incremental Auction, 2012/2013 ATSI Integration Auction, 2012/2013 RPM Second Incremental Auction, 2012/2013 RPM Third Incremental Auction, 2013/2014 BRA, 2013/2014 RPM First Incremental Auction, 2013/2014 RPM Second Incremental Auction, and the 2015/2016 BRA failed the three pivotal supplier (TPS) market structure test.[65] In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test, and six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 BRA, all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[66,67,68]
- **Imports and Exports.** Net exchange decreased 2,067.1 MW from June 1, 2011 to June 1, 2012. Net exchange, which is imports less exports, decreased due to a decrease in imports of 2,588.4 MW primarily due to the reclassification of the Duquesne resources to internal, offset by a decrease in exports of 521.3 MW.
- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market decreased by 2,764.9 MW from 9,883.4 MW on June

65 There are 26 locational deliverability areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).

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

67 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.

68 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).

1, 2011 to 7,118.5 MW on June 1, 2012. Demand-side resources include Demand Resources (DR) and Energy Efficiency (EE) resources cleared in RPM Auctions and certified/forecast interruptible load for reliability (ILR). Effective with the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency Resource type is eligible to be offered in RPM Auctions.[69]

Market Conduct

- **2012/2013 RPM Base Residual Auction.**[70] Of the 1,133 generation resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). The MMU calculated offer caps for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR values.
- **2012/2013 ATSI Integration Auction.**[71] Of the 173 generation resources which submitted offers, 26 resources elected the offer cap option of 1.1 times the BRA clearing price (15.0 percent). Unit-specific offer caps were calculated for 12 resources (6.9 percent). The MMU calculated offer caps 131 resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values.
- **2012/2013 RPM First Incremental Auction.** Of the 162 generation resources which submitted offers, unit-specific offer caps were calculated for 14 resources (8.6 percent). The MMU calculated offer caps for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values.
- **2012/2013 RPM Second Incremental Auction.** Of the 188 generation resources which submitted offers, unit-specific offer caps were calculated for 8 resources (4.3 percent). The MMU calculated offer caps for 88 resources (46.8 percent), of which 80 were based on the technology specific default (proxy) ACR values.
- **2012/2013 RPM Third Incremental Auction.** Of the 298 generation resources which submitted offers, unit-specific offer caps were calculated for two generation resources (0.7 percent). The MMU calculated offer caps for 37 generation resources (12.4 percent), of which 35 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM Base Residual Auction.**[72] Of the 1,170 generation resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). The MMU calculated offer caps for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM First Incremental Auction.** Of the 192 generation resources which submitted offers, unit-specific offer caps were calculated for 27 resources (14.1 percent). The MMU calculated offer caps for 101 resources (52.6 percent), of which 74 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM Second Incremental Auction.** Of the 163 generation resources which submitted offers, unit-specific offer caps were calculated for eight generation resources (4.9 percent). The MMU calculated offer caps for 77 generation resources (47.2 percent), of which 65 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Base Residual Auction.**[73] Of the 1,152 generation resources which submitted offers, unit-specific offer caps were calculated for 141 resources (12.2 percent). The MMU calculated offer caps for 698 resources (60.6 percent), of which 550 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM First Incremental Auction.** Of the 190 generation resources which submitted offers, unit-specific offer caps were calculated for 21 generation resources (11.1 percent). The MMU calculated offer caps for 96 generation resources (50.5 percent), of

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

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

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

72 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, see "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

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

which 71 were based on the technology specific default (proxy) ACR values.

- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 188 generation resources (16.1 percent). The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values.

Market Performance

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

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.9 percent in 2011 to 7.5 percent in 2012.[74]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor increased from 83.7 percent in 2011 to 84.1 percent in 2012.
- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (NERC) criteria, an outage may be classified as an OMC outage if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. In 2012, 12.4 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

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

Section 4 Conclusion

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

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

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in 2012. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in 2012.

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

Overview: Section 5, "Demand Response"

- **Demand-Side Response Activity.** In 2012, the total MWh of load reduction under the Economic Load Response Program increased by 124,170 MWh compared to the same period in 2011, from 17,398 MWh in 2011 to 141,568 MWh in 2012, a 714 percent increase. Total payments under the Economic Program increased by $7,106,385, from $2,052,996 in 2011 to $9,159,381 in 2012, a 346 percent increase.

  Settled MWh and credits were greater in 2012 compared to 2011, and there were more settlements submitted compared to the same period in 2010. Participation levels increased following the implementation of Order 745, on April 1, 2012, allowing payment of full LMP for demand resources. On the peak load day for 2012 (July 17, 2012), there were 2,302.4 MW registered in the Economic Load Response Program, compared to 2,041.5 MW for 2011 (July 21,2011).

  Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to participants in PJM demand side programs. In 2012, Load Management (LM) Program revenue decreased $156.0 million, or 32.0 percent, from $487 million to $331 million. Through 2012 Synchronized Reserve credits for demand side resources decreased by $4.9 million compared to the same period in 2011, from $9.4 million to $4.5 million in 2012.

- **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. 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 overcompliance to be reported when there is no actual overcompliance. 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 two events in 2012 should have been 3,713.4, rather than the 3,922.5 reported. Overall, compliance decreases from the reported 103.0 percent to 97.6 percent. This does not include locations that did not report their load during the emergency event days.

Section 5 Conclusions

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.

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market locational marginal price (LMP). End use customers pay load serving entities (LSEs) an annual amount designed to recover, among other things, the total cost of wholesale power for the year.[75] End use customers paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However, a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy, or the market price of capacity, the locational price of capacity. Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP, either on an average zonal or on a nodal basis. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. This market failure does not imply that PJM markets have failed. This market failure means that customers do not pay the actual hourly locational cost of energy as a result of the disconnect between wholesale markets and retail pricing. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the actual hourly locational price of power used by customers is determined by the wholesale power market, regardless of the average price actually paid by customers. The transition to a more functional demand side in the wholesale power market requires that the default energy price for all customers be the day-ahead or real-time hourly locational marginal price (LMP) and the locational clearing price of capacity. While the initial default energy price could be the zonal average LMP, the transition to nodal LMP pricing should begin.

PJM's Economic Load Response Program (ELRP) is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale zonal price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.[76] In PJM's Economic Load Response Program, participants have the option to receive credits for load reductions based on a more locationally defined pricing point than the zonal LMP. PJM's PRD program does incorporate some aspects of nodal pricing, although the link between the nodal wholesale price and the retail price is extremely attenuated.

FERC Order 745 was implemented effective April 1, 2012. Order 745 requires RTOs and ISOs to pay full LMP to demand resources rather than LMP less the cost of generation and transmission paid by retail customers, if the demand resources are cost effective as determined by a "Net Benefits Test" (NBT).[77] This approach is based on the view that dispatching demand resources may result in a net increase in cost to non-demand response loads, and requires the NBT as mitigation. The payment of full LMP to demand resources, effective April 1, 2012, increased participation in the Economic Load Response Program. This change explicitly permitted subsidies to be paid to retail customers on fixed rates that incorporate a fixed price of wholesale power, and

75 In PJM, load pays the average zonal LMP, which is the weighted average of the actual nodal locational marginal price. While individual customers have the option to pay nodal LMP, very few customers do so.

76 While the primary purpose of the ELRP is to replicate the hourly zonal price signal to customers on fixed retail rate contracts, customers with zonal or nodal hourly LMP contracts are currently eligible to participate in the DA scheduling and the PJM dispatch options of the Program.

77 The NBT uses a single monthly price for PJM and does not reflect hourly, locational price differences in the Real-Time and Day-Ahead markets.

to customers paying LMP for wholesale power. While the subsidy has a rationale as an incentive for fixed rate retail customers, there is no reason to provide this subsidy to LMP customers who are already receiving the price signal from the wholesale power market.

PJM's Load Management (LM) Program in the RPM market attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. The PJM market design also creates the opportunity for demand resources to participate in ancillary services markets.[78] Within the LM Program, there are new shortage pricing rules that increase maximum bid offers for the 2012/2013 DY to $1,500/MWh.

PJM's demand side programs, by design, provide a work around for end use customers that are not directly exposed to the incremental, locational costs of energy and capacity. The demand side programs should be understood as one relatively small part of a transition to a fully functional demand side for PJM markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

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 should be further modified to more accurately reflect compliance. Increases in load during event hours should not be considered zero response, 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.

78 See *2012 State of the Market Report for PJM*, Volume 2, "Section 9: Ancillary Service Markets."

Overview: Section 6, "Net Revenue"

Net Revenue

- Net revenues are significantly affected by energy prices, fuel prices and capacity prices. Revenue from the capacity market was lower in 2012 in all zones except DPL and PSEG. The combination of these factors resulted in lower total net revenues for the new entrant CT in all zones, for the new entrant CC in all zones and for the new entrant CP in all zones. The total net revenues for an IGCC plant, a nuclear plant, a solar installation and a wind installation were also affected by lower energy revenues and lower capacity revenues in 2012.

- The total net revenues did not cover the annual levelized fixed costs of a new entrant CT in any zone. The total net revenues covered the annual levelized fixed costs of a new entrant CC in three zones and covered more than 90 percent of annual levelized fixed costs in nine of 16 relevant zones. The total net revenues did not cover the annual levelized fixed costs of a new entrant CP in any zone and did not exceed 20 percent of the annual levelized fixed costs of a new entrant CP in any zone.

- The total net revenues covered only five percent of the annual levelized fixed costs of a new entrant IGCC. The total net revenues covered only 28 percent of the annual levelized fixed costs of a new entrant nuclear plant. The total net revenues covered more than 65 percent of the annual levelized fixed costs of a new entrant wind installation. The total net revenues covered 97 percent of the annual levelized fixed costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for more than 40 percent of the net revenue of a wind installation and more than 80 percent of the net revenue of a solar installation.

- Of existing sub-critical coal units, 39 percent did not recover even avoidable costs from total net revenues and of existing supercritical coal units, 15 percent did not recover even avoidable costs from total net revenues. Coal units that have not declared their intent to retire and did not cover avoidable costs from total market revenues comprise 3,725 MW of capacity. These units can be considered to be at risk of retirement.

Section 6 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.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to nonmarket and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

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.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

Overview: Section 7, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[79] 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. The rule establishes a compliance deadline of April 16, 2015. A source may obtain an extension for up to one additional year where necessary for the installation of controls. The CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing five sources for source categories with less than 30 sources).

  The MATS rule affected offers in the 2015/2016 RPM Base Residual Auction, held in May 2012.

  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.

- **Cross-State Air Pollution Rule.** 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.[80] EPA has filed a petition for rehearing. While a decision on rehearing is pending, 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).[81] 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. The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs), and particulate matter. 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 March 27, 2012, the EPA proposed a Carbon Pollution Standard for new fossil-fired electric utility generating units. The proposed standard would limit emissions from new electric generating units to 1,000 pounds of CO2 per MWh. In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the GHG rule, rejecting challenges brought by industry groups and a number of states.[82]

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. New Jersey's HEDD rule,[83] 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.[84] New Jersey's HEDD rule is implemented in two phases. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports and are subject to various behavioral requirements. After May 1, 2015, new, reconstructed or modified

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

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

81 *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 (January 14, 2013).

82 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

83 N.J.A.C. § 7:27–19.

84 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).

turbines must comply with certain technology standards. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan, describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_x emission rates.

The HEDD rule affected offers in the 2015/2016 RPM Base Residual Auction, held in May 2012.

- **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 CO2 emissions from power generation facilities. Auction prices in 2012 for the 2012-2014 compliance period were $1.93 per ton throughout the year, the price floor for 2012.

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. At the end of 2012, 68.2 percent of coal steam MW's 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. NO_x emission controlling technology is used by nearly all fossil fuel unit types, and 90.9 percent of fossil fuel fired capacity in PJM has 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 2012, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from a requirement that renewables serve 1.5 percent of all load served in Ohio, to 9.21 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards.

Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy which is greater than the marginal cost of producing energy. 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 negative LMP is equal to the marginal cost of producing minus the credit received for each MWh. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Section 7 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 8, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** PJM was a monthly net exporter of energy in the Real-Time Energy Market in January, August, September, October and December, and a net importer of energy in the remaining months of 2012.[85] The total 2012 real-time net interchange of 2,770.9 GWh (import) was greater than net interchange of -9,761.8 GWh (export) in 2011.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** PJM was a monthly net importer of energy in the Day-Ahead Energy Market in May and June, and a net exporter of energy in the remaining months of 2012. The total 2012 day-ahead net interchange of -12,548.4 GWh (export) was less than net interchange of 6,576.2 GWh (import) in 2011.

  Figure 8-1 shows the correlation between net up-to congestion transactions and the net Day-Ahead Market interchange. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 24,808 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, for 2011.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2012, gross imports in the Day-Ahead Energy Market were 364 percent of the Real-Time Energy Market's gross imports (313 percent for 2011), gross exports in the Day-Ahead Energy Market were 416 percent of the Real-Time Energy Market's gross exports (240 percent for 2011). In 2012, net interchange was -12,548.4 GWh in the Day-Ahead Energy Market and 2,770.9 GWh in the Real-Time Energy Market compared to 6,576.2 GWh in the Day-Ahead Energy Market and -9,761.8 GWh in the Real-Time Energy Market for 2011.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 69.6 percent of the total net exports: PJM/Eastern Alliant Energy Corporation (ALTE) with 26.5 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 21.8 percent, and PJM/MidAmerican Energy Company (MEC) with 21.3 percent of the net export volume.[86]

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.[87] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 78.4 percent of the total net exports: PJM/MISO with 61.9 percent, and PJM/NYIS with 16.5 percent of the net export volume.

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 77.8 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 31.5 percent, PJM/MidAmerican Energy Company (MEC) with 28.0 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 18.4 percent of the net export volume.[88]

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for 2012, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for real-time transactions.[89] The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 71.3 percent of the total net exports: PJM/SouthEXP with 43.2 percent, PJM/Northwest with 16.6 percent and PJM/ PJM/Ontario Independent Electricity System Operator (IMO) with 11.6 percent of the net export volume.

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for 2012, up-to congestion transactions had net exports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points for up-to congestion transactions accounted for 65.6 percent of the total net up-to congestion exports: PJM/SouthEXP with 49.1 percent and PJM/Ontario Independent Electricity

85 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

86 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

87 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

88 In the Day-Ahead Market, two PJM interface had a net interchange of zero (PJM/Carolina Power and Light - Western (CPLW) and PJM/City Water Light & Power (CWLP)).

89 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

System Operator (IMO) with 16.5 percent of the net export up-to congestion volume.[90]

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2012, the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average hourly flow. However, the direction of flows was consistent with price differentials in only 47 percent of hours in 2012.
- **PJM and New York ISO Interface Prices.** In 2012, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. However, the direction of flows was consistent with price differentials in only 52.8 percent of the hours in 2012.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2012, the PJM average hourly LMP at the Neptune Interface was $34.14 while the NYISO LMP at the Neptune Bus was $43.92, a difference of $9.78.[91] The average hourly flow during 2012 was -257 MW.[92] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64.5 percent of the hours in 2012.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2012, the average hourly difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average hourly flow. The average hourly flow during 2012 was -72 MW.[93] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 59.5 percent of the hours in 2012.
- **Hudson DC Line.** The Hudson direct current (DC) line will be 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 will be a bidirectional line, power flows will only be from PJM to New York. The Hudson DC line is expected to be in service by the end of the second quarter of 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.

  In 2012, net scheduled interchange was 898 GWh and net actual interchange was 672 GWh, a difference of 226 GWh, compared to net scheduled interchange of -7,072 GWh and net actual interchange of -7,576 GWh, a difference of 504 GWh in 2011.[94] This difference is inadvertent interchange.
- **PJM Transmission Loading Relief Procedures (TLRs).** PJM called fewer TLRs in 2012 than in 2011. The fact that PJM has issued only 37 TLRs in 2012, compared to 62 in 2011, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO.
- **Up-To Congestion.** Following elimination of the requirement to procure transmission for up-to congestion transactions in 2010, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 67,295 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 29,665 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011 (Figure 8-10).
- **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-

90 In the Day-Ahead Market, five PJM interface pricing points (PJM/CPLE, PJM/DUKIMP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

91 In 2012, there were 3,056 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 $32.96 while the NYISO LMP at the Neptune Bus during non-zero flows was $39.70, a difference of $6.74.

92 The average hourly flow during 2012, ignoring hours with no flow, on the Neptune DC Tie line was -393 MW.

93 The average hourly flow during 2012, ignoring hours with no flow, on the Linden VFT line was -89 MW.

94 The "Net Scheduled" values shown in Table 8-18 include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in this table does not match the interchange values shown in Table 8-1 through Table 8-6.

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.[95] These modifications are currently being evaluated by PJM.

- **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. 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.

  PJM and MISO have agreed to allow for unlimited spot market ATC on the NYISO Interface. These modifications are currently being evaluated by PJM. The MMU continues to recommend that PJM permit unlimited spot market imports and exports at all PJM Interfaces.

Section 8 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 hedging tools (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 2012, 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, and has continued to be a net exporter in most months since that time. The net direction of power flows is generally a result of price differences net of transactions costs. Up-to congestion transactions have played a significant role in power flows between balancing authorities in the Day-Ahead Market since their modification in late 2010.

In 2012, 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 53.3 percent of the hours for transactions between PJM and MISO and for 47.2 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

95 See "Meeting Minutes, "Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> . (May 16, 2011)

match as closely to the expected actual power flows as possible would result in a more economic dispatch of the entire Eastern Interconnection.

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 equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012. The average of the daily operating reserve rates paid by virtual transactions was $0.56 per MWh for the lowest five percent of all days in 2012.

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.[96] 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.

Overview: Section 9, "Ancillary Services"

Regulation Market

In 2012, the PJM Regulation Market continued 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, the Ancillary Services Optimizer (ASO). On October 1, 2012, PJM implemented Performance Based Regulation, to comply with FERC Order No. 755.[97] On November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[98]

Market Structure

- **Supply.** In 2012, 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 3.61 for 2012. This is a 20.3 percent increase over 2011 when the ratio was 3.00.
- **Demand.** The on-peak regulation requirement, as of December 31, 2012, 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. In 2011, the on-peak regulation requirement was equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement was equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in 2012 was 921 MW (840 MW off peak, and 1,015 MW on peak). This is a 4 MW decrease in the average hourly regulation demand of 925 MW in 2011 (842 MW off peak, and 1,071 MW on peak).

  Of the LSEs' obligation to provide regulation during 2012, 78.6 percent was purchased in the spot market (81.8 percent in 2011), 19.0 percent was self scheduled (15.6 percent in 2011), and 2.5 percent was purchased bilaterally (2.6 percent in 2011).[99]
- **Market Concentration.** In 2012, the PJM Regulation Market had a weighted, average Herfindahl-Hirschman Index (HHI) of 1,735 which is classified as "moderately concentrated."[100] The minimum hourly HHI was 788 and the maximum hourly

96 See Docket Nos. ER12-1338-000 and ER12-1343-000.

97 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

98 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,130 (2012)

99 Due to rounding, percentages might not sum to 100 percent.

100 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.

HHI was 4962.[101] In 2012, 43 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (82.1 percent of hours failed the three pivotal supplier test in 2011). The MMU concludes from these results that the PJM Regulation Market in 2012 was characterized by structural market power in 43 percent of the hours.

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 costs 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.[102] As of December 31, 2012, there were seven distinct resources (three generation and four demand response) offering performance regulation and following the RegD signal.

- **Price.** The weighted Regulation Market clearing price for the PJM Regulation Market for January through September, 2012 was $14.92 per MWh. This was a decrease of $2.11, or 12.4 percent, from the weighted average price for regulation in January through September, 2011. The cost of regulation from January through September, 2012 was $20.59 per MWh. This is an $11.64 (36.1 percent) decrease from the same time period in 2011.

  The Regulation Market changed significantly on October 1, 2012, with the introduction of Performance Regulation. For October through December 2012, the weighted average market clearing price was $36.52 per MWh. This is a 148.2 percent increase from the weighted average market clearing price of $14.71 for the same period in 2011. The total cost of regulation from October through December 2012, was $43.86 per MWh. This is a $23.40 per MWh increase (114.3 percent) over the cost of regulation during the same time period of 2011.

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 now merged with the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated Dominion to become the Mid-Atlantic Dominion Reserve Zone. PJM further retains the right to define new zones or subzones "as needed for system reliability."[103]

Market Structure

- **Supply.** In 2012, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side 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, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Sub-zone became the Mid-Atlantic Dominion Sub-zone on October 1, the requirement remained at 1,300 MW.

- **Market Concentration.** For all of 2012, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 3570 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in 2011 was 2637, which is classified as "highly concentrated."[104] In 2012, 56 percent of hours had a maximum market share greater than 40 percent, compared to 46 percent of hours in 2011.

101 HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. This assumption and related conclusion are not generally correct in electricity markets, like the Regulation Market, where location and unit specific parameters are significant determinants of the costs to provide service, not the relative market share of the participant. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

102 See Appendix F "Ancillary Services Markets."

103 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 74.

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

In the Mid-Atlantic Subzone, in 2012, 22 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In 2011, 63 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 2012 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 Subzone was $8.02 per MW in 2012, a $3.79 per MW decrease from 2011. The total cost of synchronized reserves per MWh in 2012 was $12.71, a $2.77 decrease (17.9 percent) from the $15.48 cost of synchronized reserve in 2011. The market clearing price was 65 percent of the total synchronized reserve cost per MW in 2012, down from 76 percent in 2011.

  One goal of shortage pricing is to have the synchronized reserve price reflect the total cost of synchronized reserve. Although both price and cost are lower in 2012, the price/cost ratio was high from October through December, 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 2012.

DASR

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[105] The purpose of this 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.[106] 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 2012, 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 2012, the required DASR was 7.03 percent of peak load forecast, down from 7.11 percent in 2011.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero; however, there is an opportunity cost associated with this direct marginal cost. As of December 31, 2012, twelve percent of offers reflected economic withholding. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[107] Units that do not offer have their offers set to zero.
- **DSR.** Demand side resources do participate in the DASR Market, but no demand resource cleared the DASR Market in 2012.

Market Performance

- **Price.** The weighted DASR market clearing price in 2012 was $0.57 per MW. In 2011, the weighted price of DASR was $0.55 per MW.

105 See 117 FERC ¶ 61,331 (2006).
106 See PJM. "Manual 13: Emergency Operations," Revision 52, (February 1, 2013); pp 11-12.
107 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 141.

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.[108]

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 all costs associated with providing this service, as defined in the tariff. In 2012, black start charges were $50.2 million. This is 151 percent higher than 2011, when total black start service charges were $20.0 million. There was substantial zonal variation. Black start zonal charges in 2012 ranged from $0.02 per MW in the ATSI zone (total charges: $119,167) to $3.62 per MW in the AEP zone (total charges: $32,468,706).

Section 9 Conclusion

The MMU continues to conclude that the results of the Regulation Market were not competitive in the first three quarters of 2012.[109] The Regulation Market results were not competitive because the 2008 changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic and the definition of opportunity cost elsewhere in the PJM tariff. This conclusion is not based on the behavior of market participants, which remains competitive.

PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU recommends that the definition of opportunity cost be consistent across all markets.

More importantly for the Regulation Market is that the design of the market was changed very 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 important parts of the design remain to be decided by FERC and 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 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. However, compliance with calls to respond to actual spinning events has been an issue. As a result, the MMU recommends that the rules for compliance be reevaluated.

The MMU concludes that the DASR Market results were competitive in 2012, 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.

108 OATT Schedule 1 § 1.3BB.

109 The *2009 State of the Market Report for PJM* provided the basis for this conclusion. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market. See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Overall, the MMU concludes that the Regulation Market results were not competitive in the first three quarters of 2012 as a result of the identified market design issues but that although it is not yet possible to reach a definitive conclusion about the new design, there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in 2012. The MMU concludes that the DASR Market results were competitive in 2012.

Overview: Section 10, "Congestion and Marginal Losses"

Marginal Loss Cost

Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. Losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal losses when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[110] The primary benefit of a marginal loss calculation is that it more accurately models the physical reality of power system losses, which permits increased efficiency and more optimal asset utilization. Marginal loss modeling creates a separate marginal loss price for every location on the power grid. This marginal loss price (MLMP) is a component of LMP that is charged to load and credited to generation.

Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss costs are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[111] Unlike the other categories of marginal loss accounting, inadvertent loss costs are common costs not directly attributable to specific participants. Inadvertent loss costs are distributed to load on a load ratio basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

Marginal loss costs can be positive or negative with respect to the reference bus. If an increase in load at a bus would decrease losses, the marginal loss component of LMP of that bus will be negative. If an increase in generation at a bus would result in an increase in losses, the marginal loss component of that bus will be negative. If an increase of load at a bus would increase losses, the marginal loss component of LMP at that bus will be positive. If an increase in generation at a bus results in a decrease of system losses, then the marginal loss component of LMP at that bus will be positive.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets priced at the marginal loss price component of LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

Marginal loss credits or loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total energy costs and net residual market adjustments, that is paid back in full to load and exports on a load ratio basis.

- **Total Marginal Loss Costs.** Total marginal loss costs in 2012 decreased by $397.9 million or 28.8 percent from 2011, from $1,379.6 million to $981.7

110 For additional information, see OATT Section 3.4.
111 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

million. Day-ahead net marginal loss costs in 2012 decreased by $426.8 million or 29.8 percent from 2011, from $1,430.5 million to $1,003.8 million. Balancing net marginal loss costs increased in 2012 by $28.9 million or 56.7 percent from 2011, from -$51.0 million to -$22.1 million.[112]

- **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 2012 ranged from $51.0 million in April to $143.4 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 that is paid back in full to load and exports on a load ratio basis.[113] The marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 million.
- **Zonal Total Marginal Loss Costs.** In 2012, zonal total marginal loss costs ranged from $2.1 million in RECO to $205.9 million in AEP. Compared to 2011, 2012 had a decrease in total marginal loss costs across the PJM control zones, except the ATSI control zone, which had an increase.[114,115]

112 Total marginal loss costs in PJM in 2012 also changed due to the addition of the DEOK Control Zone, which accounted for $3.2 million or 0.3 percent of the total marginal loss costs. The ATSI Control Zone had an increase in total marginal loss cost in 2012 because it became part of PJM on June 1, 2011, which left the first five months of 2011 out of the 2011 total marginal loss cost for ATSI.

113 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

114 Net residual market adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Net residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MW.

115 See the *2012 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses," at "Zonal Marginal Loss Costs."

Congestion Cost

Total congestion costs equal net congestion costs plus explicit congestion costs plus net inadvertent congestion costs. Net congestion costs equal load congestion payments minus generation congestion credits. Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. Net inadvertent congestion costs are the congestion costs associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour. Unlike the other categories of congestion cost accounting, inadvertent congestion costs are common costs not directly attributable to specific participants. Inadvertent congestion costs are distributed to load on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

Congestion charges can be both positive and negative. When a constraint binds, the price effects of that constraint vary. The system marginal price (SMP) is uniform for all areas, while the congestion components of Locational Marginal Price (LMP) will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[116]

Day-ahead congestion charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing congestion charges and credits are based on load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where real-time LMP has a positive congestion component, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative congestion component, negative balancing congestion costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result. Similarly, if there is a negative load deviation

116 The SMP is the price at the distributed load reference bus.

at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result.

- **Total Congestion.** Total congestion costs decreased by $470.0 million or 47.0 percent, from $999.0 million in 2011 to $529.0 million in 2012. Day-ahead congestion costs decreased by $465.1 million or 37.4 percent, from $1,245.0 million in 2011 to $779.9 million in 2012. Balancing congestion costs decreased by $4.9 million or 2.0 percent from -$246.0 million in 2011 to -$250.9 million in 2012.
- **Monthly Congestion.** Significant monthly fluctuations in congestion costs were the result of changes in load and energy import levels, changes in the dispatch of generation and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2012 ranged from $24.9 million in October to $73.1 million in July.
- **Geographic Differences in CLMP.** Differences in CPLM among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the Graceton – Raphael Road line, the Woodstock flowgate (reciprocally coordinated between PJM and MISO, West Interface, and the Bedington – Black Oak interface. (Table 10-27)
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2012.[117] Day-ahead congestion frequency increased by 60.3 percent from 155,670 congestion event hours in 2011 to 249,572 congestion event hours in 2012. Day-ahead, congestion-event hours decreased on internal PJM interfaces and transformers but increased on transmission lines and reciprocally coordinated flowgates between PJM and the MISO.

  Real-time congestion frequency decreased by 7.1 percent from 22,513 congestion event hours in 2011 to 20,917 congestion event hours in 2012. Real-time, congestion-event hours decreased on the internal PJM interfaces and transformers, but increased on transmission lines and reciprocally coordinated flowgates between PJM and MISO.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In 2012, for only 3.2 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In 2012, for 38.3 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 2012. With $68.5 million in total congestion costs, it accounted for 16.1 percent of the total PJM congestion costs in 2012. The top five constraints in terms of congestion costs together contributed $177.0 million, or 41.6 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South interface, the West interface, the Bedington - Black Oak interface, the Woodstock flowgate (a reciprocally coordinated flowgate between PJM and MISO) and the Graceton - Raphael Road line.
- **Zonal Congestion.**[118] ComEd was the most congested zone in 2012.[119] ComEd had -$334.2 million in total load costs, -$521.6 million in total generation credits and -$16.4 million in explicit congestion, resulting in $171.0 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 transmission line, Woodstock flowgate, Rantoul - Rantoul Jct flowgate, Oak Grove – Galesburg flowgate and the Prairie State - W Mt. Vernon flowgate contributed $81.0 million, or 47.4 percent of the total ComEd Control Zone congestion costs.

  The AEP Control Zone was the second most congested zone in PJM in 2012, with $104.2 million. The Monticello - East Winamac flowgate contributed $12.4 million or 11.9 percent of the total AEP Control Zone congestion cost in 2012. The Dominion Control Zone was the third most

117 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.

118 Tables reporting zonal congestion have been moved from this section of the report to Appendix G. See the *2012 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses."

119 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change. As of March 2, 2013, the total zonal congestion related numbers presented here differed from the March 2, 2013 PJM totals by $0.10 Million, a discrepancy of 0.02 percent (.00019).

congested zone in PJM in 2012, with a cost of $63.3 million.

- **Ownership.** In 2012, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2012, financial companies received $83.1 million in net congestion credits, a decrease of $91.6 million or 52.4 percent compared to 2011. In 2012, physical companies paid $612.1 million in net congestion charges, a decrease of $561.5 million or 47.8 percent compared to 2011.

Section 10 Conclusion

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 have been decreasing since 2010, due to decreases in LMP and decreases in fuel costs. Total marginal loss costs decreased in 2012 by $397.9 million or 28.8 percent from 2011, from $1,379.6 million to $981.7 million.

Marginal loss credits are distributed to load and exports. Marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 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. Total congestion costs decreased by $470.0 million or 47.0 percent, from $999.0 million in 2011 to $529.0 million in 2012. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 planning period. In the first seven months of the 2012 to 2013 planning period, total ARR and FTR revenues offset 82.1 percent of the congestion costs. FTRs were paid at 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 74.9 percent of the target allocation level for the first seven months of the 2012 to 2013 planning period.[120] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

Overview: Section 11, "Planning"

Planned Generation and Retirements

- **Planned Generation.** At December 31, 2012, 76,387 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for approximately 21,359 MW of nameplate capacity, 28.0 percent of the MW in the queues, and combined-cycle projects account for 42,724 MW, 55.8 percent of the MW in the queues.
- **Generation Retirements.** A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through January 1, 2013, and it is expected that a total of 21,524.9 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through January 1, 2013, account for 8,453.2 MW. Units planning to retire in 2013 account for 237.4 MW, or 1.1 percent of planned retirements during this period. Overall, 3,951.1 MW, or 18.4 percent of all retirements from 2011 through 2019, are expected in the AEP 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 EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, despite retirements of coal units.

120 See the *2012 State of the Market Report for PJM* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013"

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.[121] 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 7,584.2 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. The total planned costs for all of these projects are approximately 1.7 billion dollars.

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.[122] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.
- **Competitive Grid Development.** In Order No. 1000, the FERC requires that each public utility transmission provider (including PJM) remove from its FERC approved tariff and agreements, as necessary and subject to certain limitations, a federal right of first refusal (ROFR) for certain new transmission projects.[123,124] A key limitation is the ability to retain ROFR for upgrades to the existing transmission infrastructure.

Section 11 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 1000, there is not yet a robust mechanism to permit competition between transmission developers to build transmission projects. 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.

121 OATT Parts IV & VI.

122 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).

123 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011).

124 *Id.* at PP 313–322.

Overview: Section 12, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2013 to 2016 Long Term FTR Auction include the Gainesville Transformer, approximately 40 miles west of Washington, D.C., and the Monticello – East Winamac Flowgate, approximately 120 miles north of Indianapolis, IN. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2012 to 2013 planning period include the Cumberland Ave – Bush Flowgate, approximately 100 miles northwest of Indianapolis, IN and the Stephenson – Stonewall Flowgate, approximately 100 miles northwest of Washington, D.C. The geographic location of these constraints is shown in Figure 12-1.

  Market participants can also sell FTRs. In the 2013 to 2016 Long Term FTR Auction, total participant FTR sell offers were 211,316 MW, down from 251,290 MW during the 2012 to 2015 Long Term FTR Auction. In the Annual FTR Auction for the 2012 to 2013 planning period, total participant FTR sell offers were 356,299 MW, up from 337,510 MW during the 2011 to 2012 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2012) of the 2012 to 2013 planning period, total participant FTR sell offers were 3,589,825 MW, down from 3,984,782 MW for the same period during the 2011 to 2012 planning period.

- **Demand.** The PJM tariff specifies that PJM has the authority to limit the maximum number of FTR bids to 5,000 per participant for a monthly auction, or a single round of an annual auction, if necessary to avoid related system performance issues.[125] On this basis, PJM currently limits the maximum number of bids that could be submitted by a participant for any individual period in an auction to 10,000 bids.

  In the 2013 to 2016 Long Term FTR Auction, total FTR buy bids increased 15.5 percent from 2,400,881 MW to 2,772,621 MW. In the Annual FTR Auction total FTR buy bids and self-scheduled bids decreased 21.4 percent from 3,260,695 MW to 2,561,835 MW. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2012 to 2013 (June through December 2012) planning period increased 16.8 percent from 12,767,075 MW for the same time period of the prior planning period, to 14,906,684 MW.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2012 to 2013 Annual FTR Auction was low for peak and off peak FTR obligations and moderately concentrated for 24-hour FTR obligations. The ownership concentration was also moderately concentrated for peak and off peak FTR buy bid options and highly concentrated for 24-hour FTR buy bid options for the same time period. The level of concentration is descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction.

  For the 2013 through 2016 Long Term FTR Auction, financial entities purchased 80.4 percent of prevailing flow FTRs and 91.9 percent of counter flow FTRs. In the Annual FTR Auction, planning period 2012 through 2013, financial entities purchased 55.8 percent of prevailing flow FTRs and 77.8 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 81.1 percent of prevailing flow and 84.6 percent of counter flow FTRs for 2012. Financial entities owned 62.8 percent of all prevailing and counter flow FTRs, including 54.4 percent of all prevailing flow FTRs and 80.1 percent of all counter flow FTRs during the same time period.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first seven months of the 2012 to 2013 planning period were $398,630.

- **Credit Issues.** Twenty participants defaulted during 2012 from twenty one default events. The average of these defaults was $381,772 with nine based on inadequate collateral and eleven based on nonpayment. The average collateral default was $790,300 and the average nonpayment default was $47,522. The majority of these defaults were promptly cured. These defaults were not necessarily related to FTR positions.

125 OA Schedule 1 § 7.3.5(d).

Market Performance

- **Volume.** The 2013 to 2016 Long Term FTR Auction cleared 290,700 MW (10.5 percent of demand) of FTR buy bids, compared to 259,885 MW (10.8 percent) in the 2012 to 2015 Long Term FTR Auction. The 2013 to 2016 Long Term FTR Auction also cleared 56,692 MW (26.8 percent) of FTR sell offers, up from 31,288 MW (12.5 percent) in the 2012 to 2015 Long Term FTR Auction.

  For the 2012 to 2013 planning period, the Annual FTR Auction cleared 371,295 MW (14.5 percent) of FTR buy bids, compared to 387,743 MW (11.9 percent) for the 2011 to 2012 planning period. The 2012 to 2013 Annual FTR Auction also cleared 35,275 MW (9.9 percent) of FTR sell offers for the 2012 to 2013 planning period, up from 24,960 MW (7.4 percent) for the 2011 to 2012 planning period.

  For the first seven months of the 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,437,437 MW (9.6 percent) of FTR buy bids and 484,697 MW (13.5 percent) of FTR sell offers.

- **Price.** In the 2013 to 2016 Long Term FTR Auction, 95.9 percent of FTRs were purchased for less than $1 per MW, down from 96.5 percent in the previous Long Term FTR Auction. The weighted-average price for 24-hour buy bids in the Long Term FTR Auction remained constant at $0.36 per MW. Counter flow buy bid prices were negative, but approximately equal in magnitude, than prevailing flow FTR bid prices.

  For the 2012 to 2013 Annual Auction, 90.4 percent of FTRs were purchased for less than $1 per MW, up from 87.1 percent in the previous Annual FTR Auction. The weighted-average price for 24-hour buy bid obligations in the 2012 to 2013 planning period was $0.40 per MW, down from $0.68 in the 2011 to 2012 planning period.

  The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2012 to 2013 planning period was $0.12, down from $0.13 per MW in the first seven months of the 2011 to 2012 planning period.

- **Revenue.** The 2013 to 2016 Long Term FTR Auction generated $28.6 million of net revenue for all FTRs, up from $20.5 million in the 2012 to 2015 Long Term FTR Auction.

  The 2012 to 2013 planning period Annual FTR Auction generated $602.9 million of net revenue for all FTRs, down from $1,029.7 million for the 2012 to 2013 planning period.

  The Monthly Balance of Planning Period FTR Auctions generated $17.3 million in net revenue for all FTRs for the first seven months of the 2012 to 2013 planning period, down from $21.9 million for the same time period in the 2011 to 2012 planning period.

- **Revenue Adequacy.** FTRs were paid at 80.6 percent of the target allocation for the 2011 to 2012 planning period.[126] FTRs were paid at 74.8 percent of the target allocation level for the first seven months of the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $335.1 million of FTR revenues during the first seven months of the 2012 to 2013 planning period and $799.4 million during the 2011 to 2012 planning period. For the first seven months of the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were Northern Illinois Hub and Quad Cities 1. Similarly, the top sink and top source with the largest negative FTR target allocations were Quad Cities 2 and Eastern 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 -$7.6 million in profits for physical entities, of which $151.3 million was from self-scheduled FTRs, and $78.8 million for financial entities. FTR profits generally increased in the summer and winter months when congestion was higher and decreased in the shoulder months when congestion was lower. As shown in Table 12-19, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in 2012. Prevailing flow FTRs, purchased by financial entities, were not profitable in 2012.

126 Unless specifically noted, payout ratios reported in this section are calculated using PJM's method and are consistent with PJM's reported payout ratios.

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2012 to 2013 planning period were the Pleasant Prairie – Zion Flowgate, approximately 60 miles south of Milwaukee, WI, and the Breed – Wheatland Flowgate, approximately 120 miles west of Indianapolis, IN. The geographic location of these constraints is shown in Figure 12-1. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation.
- **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. In the 2012 to 2013 planning period PJM allocated a total of 9,647.6 MW with a total target allocation of $3,471,223.
- **Demand.** Total requested volume in the annual ARR allocation was 164,770 MW for the 2012 to 2013 planning period with 64,160 MW requested in Stage 1A, 27,325 MW requested in Stage 1B and 57,053 MW requested in Stage 2. This is up from 148,538 MW for the 2011 to 2011 planning period with 64,160 MW requested in Stage 1A, 22,208 MW requested in Stage 1B and 57,053 MW requested in Stage 2. The ATSI integration accounted for 5,434 MW of increased demand. The total ARR volume allocated is limited by the amount of network service and firm point-to-point transmission service. Several constraints were over allocated in the 2012 to 2013 Stage 1A ARR Allocation, consistent with the tariff, with a total over allocation of 892 MW.
- **Stage 1A Infeasibility.** In the 2012 to 2013 planning period PJM was required, per the PJM OATT Section 7.4.2 (i) to artificially increase the modeled line ratingsof several facilities over their physical capability, to accommodate Stage 1A ARR requests in the ARR Allocation model. The ultimate result of these increased line ratings is an over allocation of ARRs, which contributes to FTR underfunding. PJM was required to increase capability on nine separate facilities for a total of 892 MW.
- **ARR Reassignment for Retail Load Switching.** There were 22,543 MW of ARRs associated with approximately $226,900 of revenue that were reassigned in the first seven months of the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758,900 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Market Performance

- **Volume.** Of 164,770 MW in ARR requests for the 2012 to 2013 planning period, 97,986 MW (59.5 percent) were allocated. Market participants self scheduled 40,195 MW (45.1 percent) of these allocated ARRs as Annual FTRs. Of 148,538 MW in ARR requests for the 2011 to 2012 planning period, 102,476 MW (69.0 percent) were allocated. Market participants self scheduled 46,017 MW (44.9 percent) of these allocated ARRs as Annual FTRs.
- **Revenue.** There are no ARR revenues. ARRs are allocated to qualifying customers because they pay for the transmission system.
- **Revenue Adequacy.** For the first seven months in the 2012 to 2013 planning period, the ARR target allocations were $565.4 million while PJM collected $620.2 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through December 31, 2012, making ARRs revenue adequate. For the 2011 to 2012 planning period, the ARR target allocations were $982.9 million while PJM collected $1,091.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.
- **ARR Proration.** Stage 1A ARR requests may not be prorated. As a result, several facilities were overallocated for a total of 892 MW. Of the requested ARRs for Stage 1B, 11,581 MW were prorated and of the requested ARRs for Stage 2, 55,201 MW were prorated for the 2012 to 2013 planning period. For

the 2011 to 2012 planning period Stage 1A was not prorated nor overallocated. Some of the requested ARRs for the 2011 to 2012 planning period were prorated in Stage 1B and Stage 2 as a result of binding transmission constraints.

- **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 2012 to 2013 planning period, the total revenues received by ARR holders, including self-scheduled FTRs, offset 82.1 percent of the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 88.8 percent of the total congestion costs within PJM and for the 2010 to 2011 planning period 97.3 percent.

Section 12 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. 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.

Revenue adequacy received a lot of attention in the PJM FTR market in 2012. 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. 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 the differences between modeling in the day ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The payout ratio reported by PJM is understated. The reported payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs. For 2012 the reported payout ratio is 73.5 percent while the correctly calculated payout ratio is 76.9 percent. The MMU recommends that the calculation of the 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.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in 2012 would have been 88.1 percent instead of the reported 73.5 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 2012 from the reported 73.5 percent to 91.2 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 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; 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; the overallocation of ARRs; the appropriateness of seasonal ARR allocations; and the role of up-to congestion transactions. The MMU recommends that these issues be reviewed and modifications implemented where possible. Funding issues that persist as a result of modeling differences should be borne by FTR holders operating in the voluntary FTR market.

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 2012, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in 2012.

Table 2-1 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 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1240 with a minimum of 931 and a maximum of 1657 in 2012.
- 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, 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]

1 Analysis of 2012 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. 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 Appendix A, "PJM Geography."

2 OATT Attachment M.

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.

Overview

Market Structure

- **Supply.** Average offered supply increased by 4,180, or 2.5 percent, from 169,234 MW in the summer of 2011 to 173,414 MW in the summer of 2012.[4] The increase in offered supply was in part the result of the integration of the Duke Energy Ohio/ Kentucky (DEOK) Transmission Zone in the first quarter of 2012 and the integration of the American Transmission Systems, Inc. (ATSI) Transmission Zone in the second quarter of 2011. In 2012, 2,669 MW of new capacity were added to PJM. This new supply was more than offset by the deactivation of 45 units (6,961.9 MW) since January 1, 2012.
- **Demand.** The PJM system peak load for 2012 was 154,344 MW in the HE 1700 on July 17, 2012, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for 2011, which was 158,016 MW in the HE 1700 on July 21, 2011.[5] The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of 2012. The 2012 peak load excluding the DEOK Transmission Zone was 148,984 MW, also occurring on July 17, 2012, HE 1700, a decrease of 9,032 MW, or 5.7 percent, from the 2011 peak load.
- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.
- **Local Market Structure and Offer Capping.** 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 2012. PJM offer caps units only 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 offer-capped unit hours increased from 0.0 percent in 2011 to 0.6 percent in 2012. In the Real-Time Energy Market offer-capped unit hours increased from 0.9 percent in 2011 to 1.2 percent in 2012.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 133 units eligible for FMU or AU status in at least one month during 2012, 25 units (18.8 percent) were FMUs or AUs for all months, and 25 (18.8 percent) qualified in only one month of 2012.

  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 significant 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.
- **Local Market Structure.** In 2012, 11 Control Zones experienced congestion resulting from one or more constraints binding for 100 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.[6]

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

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).

6 See the *2012 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

not face the same cost uncertainty as gas-fired CTs. Actual participant behavior support 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.

In 2012, the unadjusted markup was negative, primarily as a result of competitive behavior by coal units. The unadjusted markup component of LMP was -$1.38 per MWh. The adjusted markup was $.43 per MWh or 1.2 percent of the PJM real-time, load-weighted average LMP of $35.23 per MWh.

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 2012 increased by 5.4 percent from 2011, from 82,546 MW to 87,011 MW. The PJM average real-time load in 2012 would have decreased by 2.0 percent from 2011, from 82,546 MW to 80,909 MW, if the DEOK and ATSI Transmission Zones were not included in this comparison for the months prior to their integration to PJM.[7]

  PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, increased by 15.6 percent from 2011, from 113,866 MW to 131,612 MW. PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, would have been 8.9 percent higher than in 2011, from 113,866 MW to 124,046 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison. The day-ahead load growth was 188.9 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 2012 increased by 3.4 percent from 2011, from 85,755 MW to 88,708 MW. PJM average real-time generation in 2012 would have decreased by 2.5 percent from 2011, from 85,755 MW to 83,630 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.

  PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, increased by 14.8 percent from 2011, from 117,130 MW to 134,479 MW. PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, would have been 4.7 percent higher than in 2011, from 117,130 MW to 122,599 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison. The day-ahead generation growth was 335.3 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Generation Fuel Mix.** During 2012, coal units provided 42.1 percent, nuclear units 34.6 percent and gas units 18.8 percent of total generation. Compared to 2011, generation from coal units decreased 7.4 percent, generation from nuclear units increased 4.0 percent, and generation from gas units increased 39.0 percent.

- **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 decreased in 2012 compared to 2011. The system average LMP was 22.7 percent lower in 2012 than in 2011, $33.11 per MWh versus $42.84 per MWh. The load-weighted average LMP was 23.3 percent lower in 2012 than in 2011, $35.23 per MWh versus $45.94 per MWh.

  PJM Day-Ahead Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.9 percent lower in 2012 than in 2011, $32.79 per MWh versus $42.52 per MWh. The load-weighted average LMP was 23.5 percent lower in 2012 than in 2011, $34.55 per MWh versus $45.19 per MWh.[8]

7 The ATSI zone was integrated on June 1, 2011. The DEOK zone was integrated on January 1, 2012. The ATSI zone was not included in this comparison for January through May 2011, and January through May 2012. The DEOK zone was not included in this comparison.

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

- **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. In 2012, 9.0 percent of real-time load was supplied by bilateral contracts, 23.2 percent by spot market purchase and 67.8 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 1.5 percentage points, reliance on spot supply decreased by 3.4 percentage points and reliance on self-supply increased by 4.9 percentage points. In 2012, 6.7 percent of day-ahead load was supplied by bilateral contracts, 22.3 percent by spot market purchases, and 71.0 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply decreased by 2.1 percentage points, and reliance on self-supply increased by 1.3 percentage points.

Scarcity

- **Scarcity Pricing Events in 2012.** PJM did not declare an administrative scarcity event in 2012. PJM's market did not experience any reserve-based shortage events in 2012.
- **Scarcity and High Load Analyses.** There were no reserve shortages in 2012. There were seven high load days and 40 high-load hours in 2012. There were 28 Hot Weather Alerts called in 2012.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in 2012, 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 4,180 MW in the summer of 2012 compared to the summer of 2011, while peak load decreased by 3,672 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in 2012 increased from 2011, from 113,866 MW to 131,612 MW, or 15.6 percent. In the Real-Time Energy Market, average load in 2012 increased from 2011, from 82,546 MW to 87,011 MW, or 5.4 percent. 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 2012 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.[9] 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

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

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 2012.

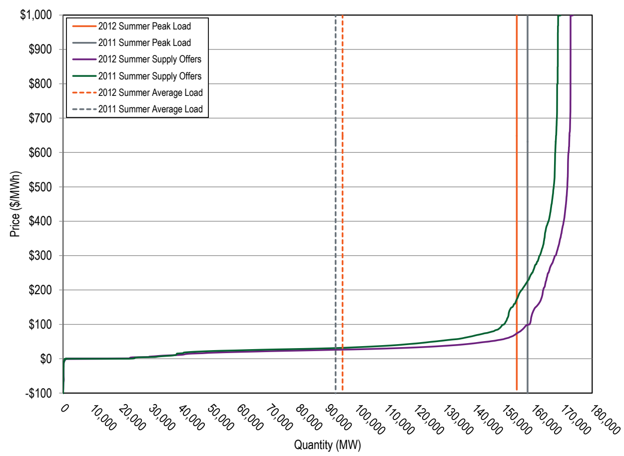
Market Structure

Supply

Average offered supply increased by 4,180 MW, or 2.5 percent, from 169,234 MW in the summer of 2011 to 173,414 MW in the summer of 2012.[10] The increase in offered supply was in part the result of the integration of the DEOK Transmission Zone in the first quarter of 2012. In 2012, 2,669 MW of new capacity were added to PJM. This new supply was more than offset by the deactivation of 45 units (6,961.9 MW) since January 1, 2012.

Figure 2-1 shows the average PJM aggregate supply curves, peak load and average load for the summers of 2011 and 2012.

Figure 2-1 Average PJM aggregate supply curves: Summer 2011 and 2012



Energy Production by Fuel Source

Compared to 2011, generation from coal units decreased 7.4 percent and generation from natural gas units increased 39.0 percent (Table 2-2). If the impact of the increased coal generation in the newly integrated ATSI and DEOK zones is eliminated, generation from coal units decreased 19.1 percent in 2012 compared to 2011.

10 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.

Table 2-2 PJM generation (By fuel source (GWh)): 2011 and 2012[11]

	2011		2012		Change in
	GWh	Percent	GWh	Percent	Output
Coal	359,410.4	47.1%	332,762.0	42.1%	(7.4%)
Standard Coal	347,940.4	45.6%	323,043.5	40.9%	(6.9%)
Waste Coal	11,470.0	1.5%	9,718.5	1.2%	(0.5%)
Nuclear	262,968.3	34.5%	273,372.2	34.6%	4.0%
Gas	106,853.3	14.0%	148,230.4	18.8%	38.7%
Natural Gas	105,049.7	13.8%	146,007.5	18.5%	39.0%
Landfill Gas	1,803.2	0.2%	2,222.3	0.3%	23.2%
Biomass Gas	0.3	0.0%	0.5	0.0%	61.0%
Hydroelectric	14,729.2	1.9%	12,649.7	1.6%	(14.1%)
Wind	11,037.0	1.4%	12,633.6	1.6%	14.5%
Waste	5,200.2	0.7%	5,177.6	0.7%	(0.4%)
Solid Waste	4,083.5	0.5%	4,200.3	0.5%	2.9%
Miscellaneous	1,116.6	0.1%	977.3	0.1%	(12.5%)
Oil	2,271.5	0.3%	5,030.9	0.6%	121.5%
Heavy Oil	1,885.4	0.2%	4,796.9	0.6%	154.4%
Light Oil	356.6	0.0%	218.9	0.0%	(38.6%)
Diesel	16.8	0.0%	9.9	0.0%	(40.9%)
Kerosene	12.8	0.0%	5.1	0.0%	(59.7%)
Jet Oil	0.1	0.0%	0.0	0.0%	(31.7%)
Solar	56.0	0.0%	233.5	0.0%	317.3%
Battery	0.2	0.0%	0.3	0.0%	36.9%
Total	762,526.0	100.0%	790,090.3	100.0%	3.6%

Table 2-3 PJM Generation (By fuel source (GWh)): 2011 and 2012; excluding ATSI and DEOK zones[12]

	2011		2012		Change in
	GWh	Percent	GWh	Percent	Output
Coal	359,410.4	47.1%	290,845.1	39.7%	(19.1%)
Standard Coal	347,940.4	45.6%	281,126.7	38.4%	(18.6%)
Waste Coal	11,470.0	1.5%	9,718.5	1.3%	(0.5%)
Nuclear	262,968.3	34.5%	260,508.9	35.6%	(0.9%)
Gas	106,853.3	14.0%	144,809.5	19.8%	35.5%
Natural Gas	105,049.7	13.8%	142,730.3	19.5%	35.9%
Landfill Gas	1,803.2	0.2%	2,078.7	0.3%	15.3%
Biomass Gas	0.3	0.0%	0.5	0.0%	61.0%
Hydroelectric	14,729.2	1.9%	12,649.7	1.7%	(14.1%)
Wind	11,037.0	1.4%	12,633.6	1.7%	14.5%
Waste	5,200.2	0.7%	5,177.6	0.7%	(0.4%)
Solid Waste	4,083.5	0.5%	4,200.3	0.6%	2.9%
Miscellaneous	1,116.6	0.1%	977.3	0.1%	(12.5%)
Oil	2,271.5	0.3%	5,025.6	0.7%	121.2%
Heavy Oil	1,885.4	0.2%	4,796.9	0.7%	154.4%
Light Oil	356.6	0.0%	215.3	0.0%	(39.6%)
Diesel	16.8	0.0%	8.2	0.0%	(50.9%)
Kerosene	12.8	0.0%	5.1	0.0%	(59.7%)
Jet Oil	0.1	0.0%	0.0	0.0%	(31.7%)
Solar	56.0	0.0%	233.5	0.0%	317.3%
Battery	0.2	0.0%	0.3	0.0%	36.9%
Total	762,526.0	100.0%	731,883.9	100.0%	(4.0%)

11 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.

12 ATSI Zone is included only for the months of June through September 2011 and June through December 2012.

Table 2-4 Monthly PJM Generation (By fuel source (GWh)): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	29,992.9	25,536.7	22,150.9	21,478.8	25,967.5	28,917.3	37,797.3	34,391.3	25,359.0	24,311.7	27,777.6	29,081.0	332,762.0
Standard Coal	28,986.9	24,723.5	21,413.8	20,918.3	25,191.9	28,126.2	36,834.5	33,470.5	24,592.4	23,633.3	26,842.3	28,309.9	323,043.5
Waste Coal	1,005.9	813.2	737.1	560.5	775.7	791.1	962.8	920.8	766.6	678.4	935.3	771.2	9,718.5
Nuclear	25,696.6	22,604.3	22,336.6	20,212.3	21,518.3	22,434.4	23,876.9	24,313.6	22,511.1	21,671.8	21,160.3	25,036.1	273,372.2
Gas	11,851.9	12,745.2	12,398.0	11,165.5	12,148.4	13,672.6	17,312.8	14,513.2	12,520.6	10,555.2	9,404.0	9,943.0	148,230.4
Natural Gas	11,671.2	12,550.6	12,192.0	10,984.6	11,965.1	13,493.5	17,130.0	14,322.1	12,340.9	10,372.3	9,233.2	9,752.2	146,007.5
Landfill Gas	180.7	194.6	206.0	181.0	183.2	179.1	182.9	190.9	179.6	182.8	170.8	190.7	2,222.3
Biomass Gas	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.5
Hydroelectric	1,187.1	953.5	1,217.3	954.4	1,399.7	1,103.9	1,052.1	1,062.5	837.6	819.5	1,018.0	1,044.1	12,649.7
Wind	1,608.3	1,167.0	1,416.3	1,345.6	885.6	882.6	546.7	415.5	677.0	1,213.7	1,022.6	1,452.6	12,633.6
Waste	430.5	408.7	409.8	395.3	443.2	473.4	469.2	455.7	408.3	399.4	433.2	450.9	5,177.6
Solid Waste	339.7	322.0	317.6	334.2	349.9	396.6	381.7	371.4	343.5	335.8	336.6	371.5	4,200.3
Miscellaneous	90.8	86.7	92.2	61.1	93.3	76.9	87.4	84.4	64.9	63.7	96.6	79.4	977.3
Oil	49.7	25.8	281.9	821.5	763.0	445.3	944.9	600.4	404.6	223.7	306.2	163.9	5,030.9
Heavy Oil	39.5	6.4	273.0	811.6	739.6	417.4	875.2	572.5	387.5	210.1	303.8	160.3	4,796.9
Light Oil	10.0	19.3	7.9	9.5	20.7	26.7	64.8	25.9	16.5	12.7	2.0	3.0	218.9
Diesel	0.2	0.1	0.8	0.2	2.3	0.7	3.0	0.3	0.6	0.9	0.3	0.4	9.9
Kerosene	0.0	0.0	0.2	0.2	0.4	0.5	1.9	1.7	0.0	0.0	0.1	0.2	5.1
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	9.8	14.3	19.1	28.1	21.5	24.8	26.1	26.1	22.9	15.3	14.0	11.5	233.5
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
Total	70,826.9	63,455.6	60,229.9	56,401.5	63,147.2	67,954.4	82,026.0	75,778.4	62,741.1	59,210.4	61,135.9	67,183.1	790,090.3

Generator Offers

The generator offers are categorized by dispatchable and self-scheduled MW and are shown in Table 2-5 and Table 2-6.[13,14] Table 2-5 shows the average hourly distribution of MW for dispatchable units by offer prices for 2012. Table 2-6 shows the average hourly distribution of MW for self-scheduled units by offer prices for 2012. Of the dispatchable MW offered by combustion turbines (CT), 26.8 percent were dispatchable at an offered range of $600 to $800. Only wind and solar units have negative offer prices.

Table 2-5 Distribution of MW for dispatchable unit offer prices: 2012

	Dispatchable (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	61.2%	11.6%	2.7%	4.7%	1.1%	81.5%
CT	0.0%	43.4%	15.7%	10.2%	26.8%	3.4%	99.5%
Diesel	0.0%	7.5%	56.3%	6.9%	1.4%	0.8%	72.9%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	10.3%	0.0%	0.0%	0.0%	0.0%	10.3%
Pumped Storage	0.0%	52.0%	0.0%	0.0%	0.0%	0.0%	52.0%
Solar	0.0%	61.7%	0.0%	0.0%	0.0%	0.0%	61.7%
Steam	0.0%	49.4%	10.8%	0.7%	0.2%	0.0%	61.1%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	23.7%	30.1%	0.0%	0.0%	0.0%	0.0%	53.8%
All Dispatchable Offers	0.5%	41.8%	9.6%	2.8%	6.4%	0.9%	62.0%

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

Table 2-6 Distribution of MW for self-scheduled unit offer prices: 2012

	Self-Scheduled (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	17.2%	1.2%	0.0%	0.0%	0.2%	18.5%
CT	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.5%
Diesel	0.0%	26.8%	0.1%	0.0%	0.0%	0.2%	27.1%
Hydro	0.0%	99.0%	0.0%	0.0%	0.0%	1.0%	100.0%
Nuclear	0.0%	89.7%	0.0%	0.0%	0.0%	0.0%	89.7%
Pumped Storage	0.0%	48.0%	0.0%	0.0%	0.0%	0.0%	48.0%
Solar	16.6%	21.7%	0.0%	0.0%	0.0%	0.0%	38.3%
Steam	0.0%	25.9%	12.3%	0.1%	0.5%	0.1%	38.9%
Transaction	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	10.4%	35.8%	0.0%	0.0%	0.0%	0.0%	46.2%
All Self-Scheduled Offers	0.2%	32.0%	5.4%	0.1%	0.2%	0.1%	38.0%

Demand

The PJM system peak load for 2012 was 154,344 MW in the HE 1700 on July 17, 2012, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for 2011, which was 158,016 MW in the HE 1700 on July 21, 2011. The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of 2012. The peak load excluding the DEOK Transmission Zone was 148,984 MW, also occurring on July 17, 2012, HE 1700, a decrease of 9,032 MW, or 5.7 percent, from the 2011 peak load.

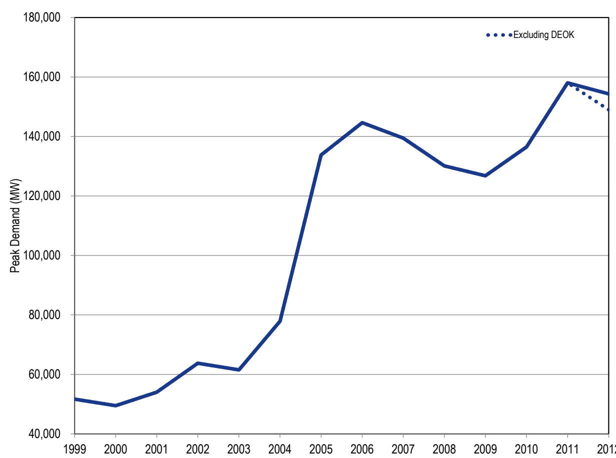
Table 2-7 shows the coincident peak loads for the years 1999 through 2012.

Table 2-7 Actual PJM footprint peak loads: 1999 to 2012[15]

Year	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 (with DEOK)	Tue, July 17	17	154,344	(3,672)	(2.3%)
2012 (without DEOK)	Tue, July 17	17	148,984	(9,032)	(5.7%)

Figure 2-2 shows the peak loads for the years 1999 through 2012.

Figure 2-2 PJM footprint calendar year peak loads: 1999 to 2012[16]

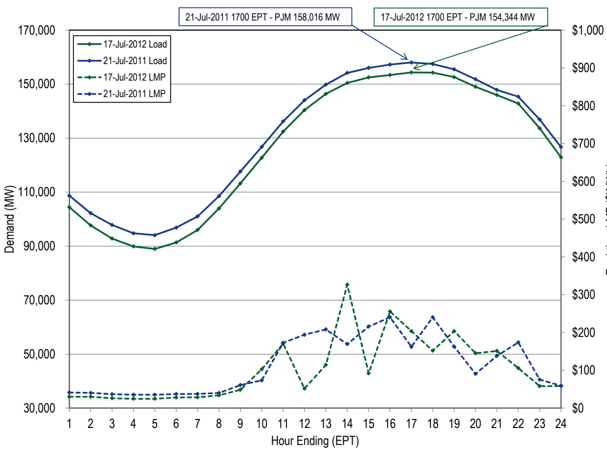


15 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load.

16 For additional information on the "PJM Integration Period", see the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Figure 2-3 compares the peak load days in 2011 and 2012. In every hour on July 21, 2011, 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 $326.72 on July 17, 2012 and peaked at $240.42 on July 21, 2011.

Figure 2-3 PJM peak-load comparison: Tuesday, July 17, 2012, and Thursday, July 21, 2011



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for 2012 indicate moderate concentration in the base load segment and intermediate segment, but high concentration in the peaking segment.[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 and generation owners' obligations to serve load were generally effective in preventing the exercise of market power in these areas during 2012. If those obligations were to change or the rules were to change, however, the market power related incentives and impacts would change as a result.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their impact on price. The direct examination of offer behavior by individual market participants is one such test. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure.[18] 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 2-8).

Actual net imports and import capability were incorporated in the hourly Energy Market HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant's market share increases with imports and decreases with exports.

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;

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.

18 HHI and market share are commonly used, but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

- **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.[19]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2012 was moderately concentrated (Table 2-8).

Table 2-8 PJM hourly Energy Market HHI: 2011[20] and 2012

	Hourly Market HHI (2011)	Hourly Market HHI (2012)
Average	1203	1240
Minimum	889	931
Maximum	1564	1657
Highest market share (One hour)	30%	32%
Average of the highest hourly market share	21%	23%
# Hours	8,760	8,784
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

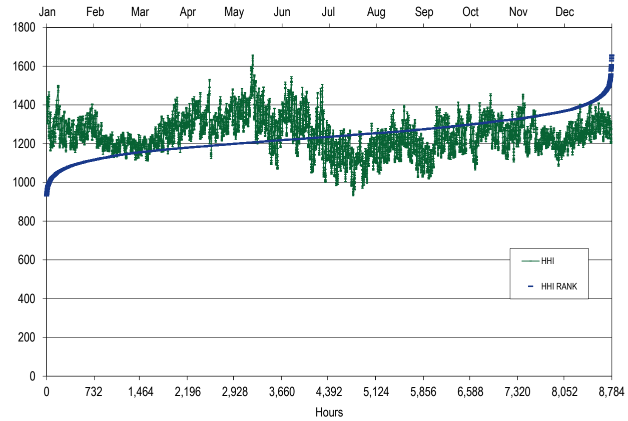
Table 2-9 includes 2012 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 2-9 PJM hourly Energy Market HHI (By supply segment): 2011 and 2012

	2011			2012		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1034	1224	1534	1025	1239	1624
Intermediate	676	1831	7964	787	1625	3974
Peak	596	6034	10000	679	5262	10000

Figure 2-4 presents the 2012 hourly HHI values in chronological order and an HHI duration curve.

Figure 2-4 PJM hourly Energy Market HHI: 2012



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. 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.

PJM has clear rules limiting the exercise of local market power.[21] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

19 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).
20 This analysis includes all hours in 2012, regardless of congestion.

21 OA Schedule 1, § 6.4.2.

Under existing rules, PJM does not apply offer capping to suppliers when structural market conditions, as measured by the three pivotal supplier test, indicate that such suppliers are reasonably likely to behave in a competitive manner. The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

PJM's three pivotal supplier test represents the practical application of the FERC market power tests in real time.[22] The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

Levels of offer capping have historically been low in PJM, as shown in Table 2-10.

Table 2-11 presents data on the frequency with which units were offer capped in 2011 and 2012.

Table 2-11 shows that a small number of units are offer capped for a significant number of hours or for a significant proportion of their run hours.

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.

Table 2-10 Offer-capping statistics: 2008 to 2012

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.9%	0.4%	0.0%	0.0%
2012	1.2%	0.8%	0.6%	0.4%

Table 2-11 Real-time offer-capped unit statistics: 2011 and 2012

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:		Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2012	0	2	0	1	1	1
	2011	0	0	0	6	9	4
80% and < 90%	2012	0	1	0	0	2	4
	2011	0	0	1	2	5	9
75% and < 80%	2012	0	0	0	0	1	2
	2011	0	0	0	0	3	3
70% and < 75%	2012	0	0	0	0	1	2
	2011	0	0	0	0	0	10
60% and < 70%	2012	1	0	0	1	1	8
	2011	0	1	0	1	1	20
50% and < 60%	2012	7	0	1	0	1	10
	2011	0	0	0	2	13	23
25% and < 50%	2012	5	1	1	2	8	49
	2011	2	0	0	5	19	70
10% and < 25%	2012	6	0	0	3	13	58
	2011	9	2	0	0	2	49

22 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test."

Local Market Structure

In 2012, the AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, PECO, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 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 2012.[23] The AECO, AEP, DAY, JCPL, Met-Ed, PENELEC, PPL and RECO Control Zones were not affected by constraints binding for 100 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, 2012, through December 31, 2012. 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.

Information is provided for each constraint including the number of tests applied and the number of tests that could have resulted in offer capping.[24] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

Table 2-12 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 regional 500 kV constraints.

Table 2-12 Three pivotal supplier test details for regional constraints: 2012

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	332	482	16	4	13
	Off Peak	247	478	16	8	9
AEP-DOM	Peak	276	373	8	0	8
	Off Peak	214	353	9	0	8
AP South	Peak	366	550	11	1	10
	Off Peak	347	557	11	1	10
Bedington - Black Oak	Peak	93	133	10	1	9
	Off Peak	114	102	9	1	8
Central	Peak	347	451	15	2	13
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	426	656	15	8	7
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	466	576	16	5	11
	Off Peak	350	600	16	9	7

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 2-13 provides, for the identified seven regional 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.

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

24 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

Table 2-13 Summary of three pivotal supplier tests applied for regional constraints 2012

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	2,086	112	5%	29	1%	26%
	Off Peak	1,021	21	2%	3	0%	14%
AEP-DOM	Peak	824	49	6%	26	3%	53%
	Off Peak	441	22	5%	18	4%	82%
AP South	Peak	4,078	109	3%	25	1%	23%
	Off Peak	2,097	36	2%	6	0%	17%
Bedington - Black Oak	Peak	1,074	36	3%	3	0%	8%
	Off Peak	282	8	3%	0	0%	0%
Central	Peak	27	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Eastern	Peak	160	9	6%	4	3%	44%
	Off Peak	NA	NA	NA	NA	NA	NA
Western	Peak	1,270	118	9%	31	2%	26%
	Off Peak	482	51	11%	4	1%	8%

Ownership of Marginal Resources

Table 2-14 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner.[25] The contribution of each marginal resource to price at each load bus is calculated for 2012, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in 2012, the offers of one company contributed 21.9 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 51.5 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during 2011, the offers of one company contributed 15.4 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 48 percent of the real-time, load-weighted, average PJM system LMP.

Table 2-14 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): 2012 and 2011

2012		2011	
Company	Percent of Price	Company	Percent of Price
1	21.9%	1	15.4%
2	12.9%	2	14.1%
3	8.9%	3	10.1%
4	7.8%	4	8.3%
5	7.8%	5	6.9%
6	6.1%	6	6.7%
7	5.7%	7	5.3%
8	5.2%	8	4.8%
9	3.7%	9	4.4%
Other (56 companies)	19.9%	Other (47 companies)	23.9%

Table 2-15 shows the contribution of PJM day ahead, load-weighted LMP by individual marginal resource owner.[26] The contribution of each marginal resource to price at each load bus is calculated for 2012, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

Table 2-15 Marginal unit contribution to PJM day-ahead, load-weighted LMP (By parent company): 2012 and 2011

2012		2011	
Company	Percent of Price	Company	Percent of Price
1	16.0%	1	17.3%
2	6.2%	2	8.6%
3	6.1%	3	7.8%
4	5.8%	4	5.2%
5	4.6%	5	4.5%
6	4.4%	6	4.2%
7	4.1%	7	4.0%
8	4.0%	8	3.4%
9	3.5%	9	3.3%
Other (142 companies)	45.4%	Other (150 companies)	41.8%

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.

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

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

Table 2-16 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 2012, coal units were 58.8 percent and natural gas units were 30.4 percent of the total marginal resources. In 2011, coal units were 67.3 percent and natural gas units were 26.5 percent of the total marginal resources.[27]

Table 2-16 Type of fuel used (By real-time marginal units): 2012 and 2011

Fuel Type	2012	2011
Coal	58.8%	67.3%
Gas	30.4%	26.5%
Municipal Waste	0.1%	0.1%
Oil	6.0%	2.6%
Other	0.5%	0.4%
Uranium	0.0%	0.0%
Wind	4.2%	2.9%

Table 2-17 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2012, Up-to Congestion transactions were 88.4 percent of the total marginal resources. In comparison, Up-to Congestion transactions were 73.4 percent of the total marginal resources in 2011.

Table 2-17 Day-ahead marginal resources by type/fuel: 2011 and 2012

Type/Fuel	2012	2011
Up-to Congestion Transaction	88.4%	73.4%
DEC	4.3%	12.4%
INC	3.8%	7.5%
Coal	2.3%	4.7%
Gas	1.0%	1.5%
Dispatchable Transaction	0.1%	0.2%
Price Sensitive Demand	0.0%	0.2%
Wind	0.0%	0.1%
Oil	0.0%	0.0%
Diesel	0.0%	0.0%
Municipal Waste	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.[28] 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. This index calculation method weights the impact of individual unit markups using sensitivity factors, to reflect their relative importance in the system dispatch solution. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Mark Up Conduct

Table 2-18 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. A unit is assigned to a price category for each dispatch solution associated with the interval in which it was marginal, based on its offer price at that time. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

27 The percentages of marginal fuel reported in the *2011 State of the Market Report for PJM*, Volume I, were based on both Locational Pricing Algorithm (LPA) and dispatch (SCED) marginal resources. In this report, 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."

28 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.

Table 2-18 Average, real-time marginal unit markup index (By price category): 2012 and 2011

	2012			2011		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.25)	29.0%	(0.10)	($3.89)	12.1%
$25 to $50	(0.05)	($2.67)	52.3%	(0.07)	($6.58)	68.7%
$50 to $75	0.05	$1.23	4.5%	(0.02)	($6.05)	8.3%
$75 to $100	0.28	$24.25	0.6%	0.12	$6.80	1.6%
$100 to $125	0.23	$23.66	0.5%	0.25	$25.53	0.7%
$125 to $150	0.20	$27.69	0.2%	0.25	$33.72	0.4%
>= $150	0.04	$9.47	5.5%	0.12	$24.73	4.1%

Day-Ahead Mark Up Conduct

Table 2-19 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 2-19 Average marginal unit markup index (By offer price category): 2012 and 2011

	2012			2011		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($2.69)	29.5%	(0.10)	($3.76)	11.0%
$25 to $50	(0.05)	($2.43)	67.3%	(0.06)	($4.70)	82.3%
$50 to $75	0.09	$4.20	2.7%	(0.01)	($5.60)	5.2%
$75 to $100	0.45	$36.22	0.1%	0.11	$4.94	0.9%
$125 to $150	0.00	$0.00	0.0%	0.05	$1.54	0.2%
$125 to $150	(0.06)	($8.33)	0.1%	(0.07)	($20.72)	0.1%
>= $150	0.03	$4.84	0.2%	0.18	$30.70	0.3%

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.[29]

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

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

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 marginal units with price-based offers, and the system price, based on the cost-based offers of those marginal units.

Table 2-20 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 2-20 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 2-18.

Table 2-20 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type:[30] 2012 and 2011

		2012		2011	
Fuel Type	Unit Type	Markup Component of LMP	Percent	Markup Component of LMP	Percent
Coal	Steam	($1.70)	123.1%	($0.22)	5.1%
Gas	CC	$0.42	(30.6%)	($3.66)	84.2%
Gas	CT	($0.03)	2.5%	($0.36)	8.2%
Gas	Diesel	$0.02	(1.7%)	$0.01	(0.3%)
Gas	Steam	($0.03)	2.2%	($0.01)	0.2%
Municipal Waste	Diesel	$0.00	0.0%	$0.00	0.0%
Municipal Waste	Steam	$0.02	(1.5%)	$0.05	(1.2%)
Oil	CT	$0.01	(0.6%)	$0.00	(0.0%)
Oil	Diesel	$0.00	(0.1%)	($0.00)	0.0%
Oil	Steam	($0.08)	5.6%	($0.17)	4.0%
Other	Solar	$0.00	(0.0%)	$0.00	0.0%
Other	Steam	($0.00)	0.3%	($0.00)	0.1%
Uranium	Steam	$0.00	0.0%	($0.00)	0.0%
Wind	Wind	($0.00)	0.3%	$0.01	(0.2%)
Total		($1.38)	100.0%	($4.35)	100.0%

30 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.

Markup Component of Real-Time System Price

Table 2-21 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2012, -$1.38 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In 2012, the markup component of LMP was -$2.89 per MWh off peak and $0.04 per MWh on peak. In comparison, in 2011, -$4.35 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In 2011, the markup component of LMP was -$5.00 per MWh off peak and $3.74 per MWh on peak.

Table 2-21 Monthly markup components of real-time load-weighted LMP: 2012 and 2011

	2012			2011		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.25)	($3.51)	($2.98)	($5.60)	($2.76)	($8.59)
Feb	($2.07)	($2.92)	($1.26)	($7.56)	($5.46)	($9.56)
Mar	($2.24)	($2.51)	($2.00)	($5.77)	($5.09)	($6.36)
Apr	($2.71)	($3.60)	($1.86)	($8.93)	($7.31)	($10.45)
May	($1.10)	($3.34)	$0.94	($6.51)	($5.17)	($7.81)
Jun	($2.68)	($3.24)	($2.18)	($2.64)	($8.08)	$1.68
Jul	$3.38	($2.36)	$8.82	($1.32)	($5.49)	$2.99
Aug	($0.90)	($2.30)	$0.20	($3.51)	($7.97)	$0.02
Sep	($0.70)	($1.89)	$0.60	($3.36)	($4.59)	($2.24)
Oct	($1.14)	($2.99)	$0.38	($4.43)	($4.04)	($4.82)
Nov	($1.46)	($2.85)	($0.11)	($3.74)	($3.47)	($3.99)
Dec	($2.98)	($3.27)	($2.65)	($1.44)	($1.26)	($1.62)
Total	($1.38)	($2.89)	$0.04	($4.35)	($5.00)	($3.74)

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-22. The smallest zonal all hours average markup component for 2012 was in the DAY Control Zone, -$1.71 per MWh, while the highest all hours' average zonal markup component for 2012 was in the Pepco Control Zone, -$0.85 per MWh. On peak, the smallest annual average zonal markup was in the DEOK Control Zone, -$0.41 per MWh, while the highest annual average zonal markup was in the JCPL Control Zone, $0.72 per MWh.

Table 2-22 Average real-time zonal markup component: 2012 and 2011

	2012			2011		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($1.19)	($2.68)	$0.26	($3.69)	($4.94)	($2.50)
AEP	($1.67)	($2.98)	($0.38)	($4.27)	($4.73)	($3.83)
APS	($1.51)	($2.96)	($0.11)	($5.18)	($5.30)	($5.07)
ATSI	($1.63)	($3.10)	($0.24)	($2.94)	($5.05)	($1.00)
BGE	($1.05)	($2.46)	$0.31	($4.66)	($5.31)	($4.05)
ComEd	($1.38)	($3.04)	$0.16	($2.56)	($3.03)	($2.13)
DAY	($1.71)	($3.11)	($0.40)	($4.04)	($4.75)	($3.39)
DEOK	($1.68)	($3.01)	($0.41)	NA	NA	NA
Dominion	($1.03)	($2.53)	$0.42	($5.71)	($5.91)	($5.51)
DPL	($1.40)	($3.00)	$0.16	($4.46)	($5.39)	($3.56)
DUQ	($1.46)	($2.97)	($0.02)	($4.28)	($4.91)	($3.68)
JCPL	($1.02)	($2.93)	$0.72	($4.36)	($5.54)	($3.31)
Met-Ed	($1.44)	($3.02)	$0.02	($4.62)	($5.34)	($3.96)
PECO	($1.29)	($2.78)	$0.12	($4.63)	($5.55)	($3.77)
PENELEC	($1.60)	($3.12)	($0.17)	($4.70)	($5.02)	($4.41)
Pepco	($0.85)	($2.51)	$0.69	($4.83)	($5.51)	($4.21)
PPL	($1.53)	($3.04)	($0.13)	($4.61)	($5.32)	($3.96)
PSEG	($1.14)	($2.77)	$0.37	($5.10)	($6.10)	($4.19)
RECO	($0.99)	($2.89)	$0.63	($3.12)	($4.31)	($2.12)

Markup by Real-Time System Price Levels

The price component measure uses load-weighted, price-based LMP and load-weighted LMP computed using cost-based offers for all marginal units. The markup component of price is computed by calculating the system price, based on the cost-based offers of the marginal units and comparing that to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-23 shows the average markup component of observed prices when the PJM system LMP was in the identified price range.

Table 2-23 Average real-time markup component (By price category): 2012 and 2011

	2012		2011	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.78)	24.1%	($0.33)	5.4%
$25 to $50	($1.83)	65.5%	($5.47)	73.5%
$50 to $75	$0.34	4.5%	($0.71)	9.4%
$75 to $100	$0.24	1.4%	$0.55	3.4%
$100 to $125	$0.10	0.6%	$0.46	1.6%
$125 to $150	$0.11	0.2%	$0.32	0.8%
>= $150	$0.44	0.5%	$0.83	1.1%

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 2-24.

Table 2-24 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: 2012 and 2011

		2012		2011	
Fuel Type	Unit Type	Markup Component of LMP	Percent	Markup Component of LMP	Percent
Coal	Steam	($1.69)	90.9%	($1.16)	32.2%
Diesel	Diesel	$0.00	0.0%	$0.00	0.0%
Gas	CT	$0.06	(3.2%)	$0.04	(1.0%)
Gas	Diesel	$0.00	0.0%	$0.00	0.0%
Gas	Steam	($0.17)	9.0%	($2.32)	64.4%
Municipal Waste	Steam	($0.00)	0.1%	($0.00)	0.0%
Oil	Steam	($0.06)	3.2%	($0.16)	4.4%
Wind	Wind	$0.00	0.0%	$0.00	0.0%
Total		($1.86)	100.0%	($3.60)	100.0%

Markup Component of Day-Ahead System Price

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

Table 2-25 shows the markup component of average prices and of average monthly on-peak and off-peak prices.

Table 2-25 Monthly markup components of day-ahead, load-weighted LMP: 2011 and 2012

	2012			2011		
	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)	($3.37)	($4.12)	($2.66)
Feb	($3.01)	($3.61)	($2.38)	($3.68)	($3.92)	($3.43)
Mar	($2.30)	($1.99)	($2.63)	($2.47)	($1.83)	($3.21)
Apr	($2.67)	($2.36)	($2.98)	($3.81)	($3.03)	($4.66)
May	($1.52)	($1.11)	($1.97)	($3.82)	($2.75)	($4.94)
Jun	($1.93)	($1.09)	($2.88)	($4.48)	($3.48)	($5.76)
Jul	$0.35	$2.60	($2.07)	($3.07)	($0.43)	($5.65)
Aug	($1.86)	($0.95)	($3.05)	($3.59)	($1.24)	($6.60)
Sep	($1.75)	($1.36)	($2.10)	($5.76)	($4.27)	($7.43)
Oct	($0.95)	($0.06)	($2.03)	($2.56)	($2.82)	($2.29)
Nov	($2.05)	($0.86)	($3.29)	($4.03)	($3.94)	($4.13)
Dec	($2.42)	($1.97)	($2.82)	($2.68)	($1.81)	($3.52)
Total	($1.86)	($1.14)	($2.63)	($3.60)	($2.72)	($4.55)

Markup Component of Day-Ahead Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-26.

Table 2-26 Day-ahead, average, zonal markup component: 2011 and 2012

	2012			2011		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.56)	($0.66)	($2.53)	($3.50)	($3.13)	($3.91)
AEP	($1.94)	($1.26)	($2.65)	($3.45)	($2.41)	($4.54)
AP	($1.87)	($1.30)	($2.47)	($3.53)	($2.24)	($4.90)
ATSI	($1.99)	($1.32)	($2.72)	($3.44)	($1.72)	($5.34)
BGE	($1.86)	($1.19)	($2.57)	($4.45)	($4.02)	($4.91)
ComEd	($1.77)	($1.17)	($2.44)	($2.41)	($1.35)	($3.58)
DAY	($1.90)	($1.19)	($2.68)	($3.60)	($2.68)	($4.62)
DEOK	($1.85)	($1.17)	($2.56)	NA	NA	NA
DLCO	($1.83)	($1.13)	($2.59)	($2.78)	($1.07)	($4.63)
Dominion	($1.79)	($1.03)	($2.57)	($4.31)	($3.41)	($5.25)
DPL	($1.67)	($0.85)	($2.55)	($3.69)	($3.21)	($4.18)
JCPL	($1.54)	($0.66)	($2.53)	($3.66)	($3.57)	($3.76)
Met-Ed	($1.85)	($1.13)	($2.65)	($3.89)	($3.49)	($4.32)
PECO	($1.71)	($0.98)	($2.49)	($3.65)	($3.18)	($4.17)
PENELEC	($2.07)	($1.50)	($2.69)	($5.03)	($3.33)	($6.95)
Pepco	($1.86)	($1.25)	($2.52)	($4.33)	($3.78)	($4.93)
PPL	($2.04)	($1.43)	($2.71)	($3.67)	($3.39)	($3.98)
PSEG	($1.59)	($0.61)	($2.69)	($3.64)	($3.16)	($4.18)
RECO	($1.49)	($0.54)	($2.63)	($3.26)	($3.23)	($3.30)

Markup by Day-Ahead System Price Levels

The annual average markup component of the identified price range and its frequency are shown in Table 2-27.

Table 2-27 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-27 Average, day-ahead markup (By LMP category): 2011 and 2012

	2012		2011	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($3.25)	21.0%	($12.90)	3.1%
$25 to $50	($2.69)	74.9%	($5.25)	82.8%
$50 to $75	$2.06	3.0%	($2.98)	10.6%
$75 to $100	$6.62	0.6%	$1.38	1.8%
$100 to $125	$18.93	0.2%	$6.54	0.7%
$125 to $150	$4.54	0.1%	$3.58	0.5%
>= $150	$16.80	0.2%	$18.50	0.5%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[31] 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 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 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.[32] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[33,34]

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, 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

31 110 FERC ¶ 61,053 (2005).
32 OA, Schedule 1 § 6.4.2.
33 114 FERC ¶ 61, 076 (2006).
34 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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 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 significant 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.

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.[35]

Table 2-28 shows, by month, the number of FMUs and AUs in 2011 and 2012. For example, in June 2012, there were 22 FMUs and AUs in Tier 1, 13 FMUs and AUs in Tier 2, and 48 FMUs and AUs in Tier 3.

Table 2-28 Number of frequently mitigated units and associated units (By month): 2011 and 2012

	FMUs and AUs							
	2011				2012			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	46	22	66	134	26	21	52	99
February	34	43	60	137	26	22	47	95
March	30	46	66	142	25	17	47	89
April	34	45	62	141	23	17	46	86
May	37	48	59	144	23	14	47	84
June	31	50	61	142	22	13	48	83
July	45	32	43	120	25	11	50	86
August	33	14	44	91	25	23	43	91
September	18	19	55	92	17	6	33	56
October	31	24	53	108	10	18	14	42
November	20	28	49	97	9	21	10	40
December	20	26	51	97	14	17	10	41

Figure 2-5 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February, 2006.

Figure 2-5 Frequently mitigated units and associated units (By month): February, 2006 through December, 2012

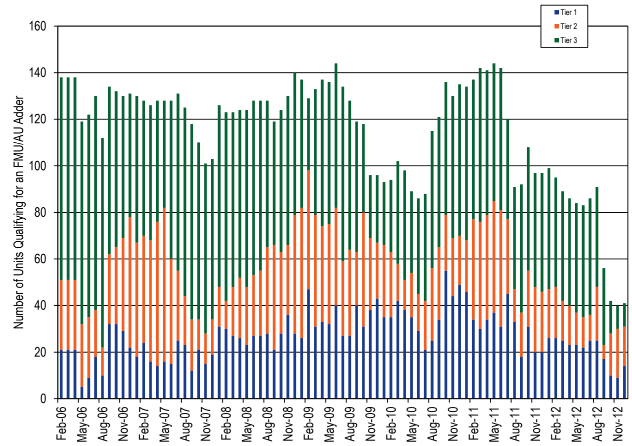


Table 2-29 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2011 and 2012. Of the 133 units eligible in at least one month during 2012, 25 units (18.8 percent) were FMUs or AUs for all months, and 25 (18.8 percent) qualified in only one month of 2012.

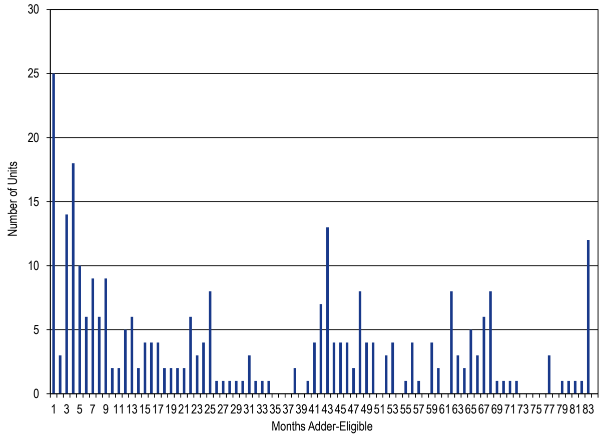
35 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Table 2-29 Frequently mitigated units and associated units total months eligible: 2011 and 2012

Months Adder-Eligible	FMU & AU Count	
	2011	2012
1	11	25
2	1	12
3	4	4
4	19	9
5	12	2
6	33	4
7	24	14
8	14	16
9	5	15
10	8	5
11	3	2
12	54	25
Total	188	133

Figure 2-6 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, 2012, there have been 303 unique units that have qualified for an FMU adder in at least one month. Of these 303 units, no unit qualified for an adder in all potential months. Twelve units qualified in 83 of the 84 possible months, and 120 of the 303 units (39.6 percent) have qualified for an adder in more than half of the possible months.

Figure 2-6 Frequently mitigated units and associated units total months eligible: February, 2006 through December, 2012



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 2012 increased by 5.4 percent from 2011, from 82,546 MW to 87,011 MW. The PJM average real-time load in 2012 would have decreased by 2.0 percent from 2011, from 82,546 MW to 80,909 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.[36]

PJM average day-ahead load, including DECs and up-to congestion transactions, in 2012 increased by 15.6 percent from 2011, from 113,866 MW to 131,612 MW. PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, would have increased by 8.9 percent from 2011, from 113,866 MW to 124,046 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.

The day-ahead load growth was 188.9 percent higher than the real-time load growth because of the continued growth of up-to congestion transactions. If 2012 up-to congestion transactions had been held to 2011 levels, the day-ahead load, including DECs and up-to congestion transactions, would have increased 1.4 percent instead of 15.6 percent and day-ahead load growth would have been 74.1 percent lower than the real-time load growth.

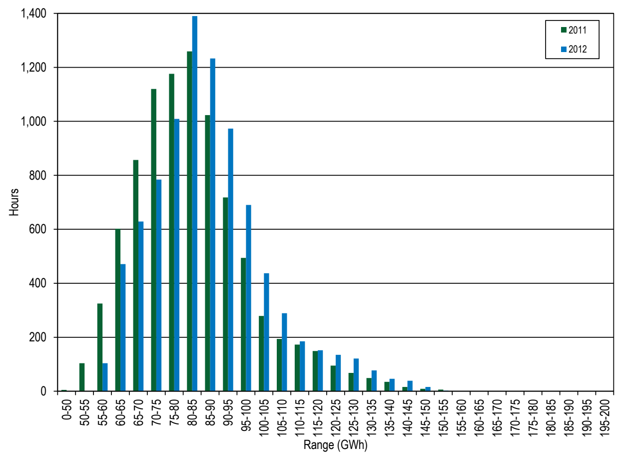
36 The ATSI zone was integrated on June 1, 2011. The DEOK zone was integrated on January 1, 2012. The ATSI zone was not included in this comparison for January through May 2011, and January through May 2012. The DEOK zone was not included in this comparison.

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real-time load for 2011 and 2012.[37]

Figure 2-7 PJM real-time accounting load: 2011 and 2012[38]



PJM Real-Time, Average Load

Table 2-30 presents summary real-time load statistics for the 15-year period 1998 to 2012. 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.[39]

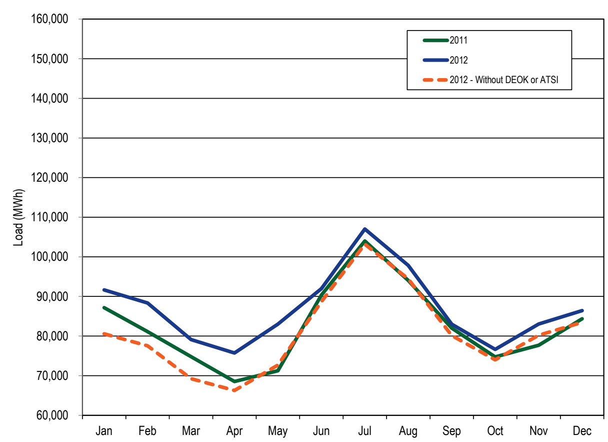
Table 2-30 PJM real-time average hourly load: 1998 through 2012[40]

	PJM Real-Time Load (MWh)		Year-to-Year Change	
Year	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,578	5,511	NA	NA
1999	29,641	5,955	3.7%	8.1%
2000	30,113	5,529	1.6%	(7.2%)
2001	30,297	5,873	0.6%	6.2%
2002	35,776	7,976	18.1%	35.8%
2003	37,395	6,834	4.5%	(14.3%)
2004	49,963	13,004	33.6%	90.3%
2005	78,150	16,296	56.4%	25.3%
2006	79,471	14,534	1.7%	(10.8%)
2007	81,681	14,618	2.8%	0.6%
2008	79,515	13,758	(2.7%)	(5.9%)
2009	76,034	13,260	(4.4%)	(3.6%)
2010	79,611	15,504	4.7%	16.9%
2011	82,546	16,156	3.7%	4.2%
2012	87,011	16,213	5.4%	0.3%

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads in 2012 with those in 2011.

Figure 2-8 PJM real-time monthly average hourly load: 2011 and 2012



PJM real-time load is significantly affected by temperature. PJM uses the Temperature-Humidity Index (THI), the Winter Weather Parameter (WWP) and the average temperature as weather variables in the PJM load forecast model for different seasons.[41] Table

37 All real-time load data in Section 2, "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.

38 Each range on the vertical axis includes the start value and excludes the end value.

39 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.*

40 The version of this table in the *2012 Quarterly State of the Market Report for PJM: January through March* incorrectly reported the standard deviation.

41 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, TOL and WAL.

2-31 shows the load weighted THI, WWP and average temperature for cooling, heating and shoulder seasons.[42]

Table 2-31 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): Cooling, heating and shoulder months of 2007 through 2012

	Summer THI	Winter WWP	Shoulder Average Temperature
2007	74.84	24.99	53.87
2008	74.48	26.93	51.13
2009	73.15	24.02	52.80
2010	76.09	24.47	54.73
2011	75.14	25.20	53.19
2012	74.92	30.26	54.64

Day-Ahead Load

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

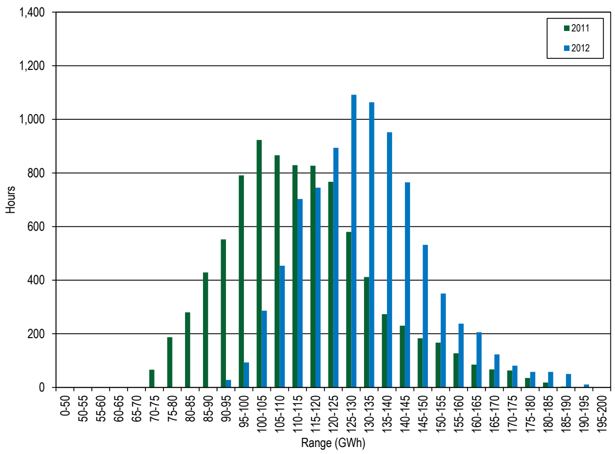
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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 Transactions.** 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.[43] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. 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.[44]

PJM Day-Ahead Load Duration

Figure 2-9 shows the hourly distribution of PJM day-ahead load for 2011 and 2012.

Figure 2-9 PJM day-ahead load: 2011 and 2012



PJM Day-Ahead, Average Load

Table 2-32 presents summary day-ahead load statistics for the 12-year period 2001 to 2012.

42 The Summer THI is calculated by taking average of daily maximum THI in June, July, August and September. The Winter WWP is calculated by taking average of daily minimum WWP in January and February (December of each year is not included). Average temperature is used for the remaining months. For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 21 (October 1, 2012), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

43 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

44 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.

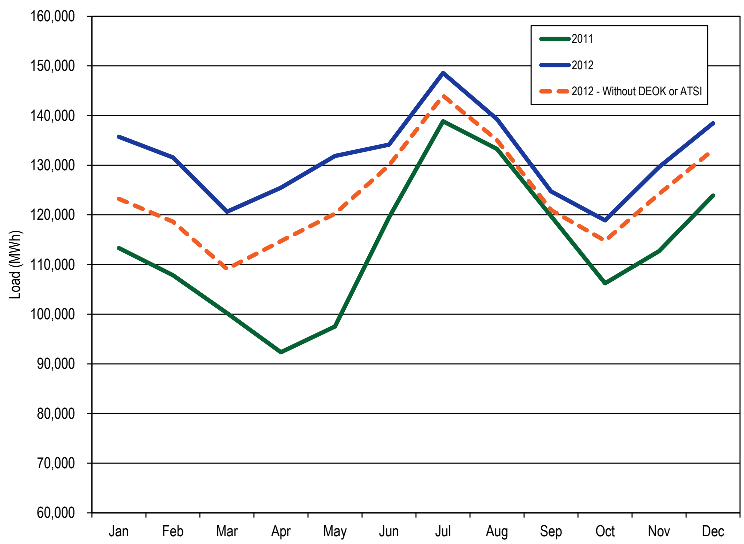
Table 2-32 PJM day-ahead average load: 2001 through 2012[45]

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2001	33,303	67	33,370	6,526	200	6,562	NA	NA	NA
2002	42,131	174	42,305	10,130	303	10,161	26.5%	161.2%	26.8%
2003	44,328	346	44,674	7,877	310	7,841	5.2%	98.6%	5.6%
2004	61,034	1,068	62,101	16,318	905	16,654	37.7%	208.9%	39.0%
2005	92,002	1,532	93,534	17,381	886	17,643	50.7%	43.5%	50.6%
2006	94,793	3,734	98,527	16,048	1,555	16,723	3.0%	143.8%	5.3%
2007	100,912	4,591	105,503	16,190	1,567	16,686	6.5%	23.0%	7.1%
2008	95,522	6,381	101,903	15,439	1,889	15,871	(5.3%)	39.0%	(3.4%)
2009	88,707	6,234	94,941	14,896	2,133	15,869	(7.1%)	(2.3%)	(6.8%)
2010	90,985	12,952	103,937	17,014	7,778	21,358	2.6%	107.8%	9.5%
2011	91,713	22,153	113,866	17,830	5,767	20,708	0.8%	71.0%	9.6%
2012	93,267	38,344	131,612	17,121	7,978	17,421	1.7%	73.1%	15.6%

PJM Day-Ahead, Monthly Average Load

Figure 2-10 compares the day-ahead, monthly average hourly loads of 2012 with those of 2011.

Figure 2-10 PJM day-ahead monthly average hourly load: 2011 and 2012



45 The version of this table in the *2012 Quarterly State of the Market Report for PJM: January through March* incorrectly reported the standard deviation.

Real-Time and Day-Ahead Load

Table 2-33 presents summary statistics for 2011 and 2012 day-ahead and real-time loads.

Table 2-33 Cleared day-ahead and real-time load (MWh): 2011 and 2012

		Day Ahead					Real Time	Average Difference	
	Year	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	2011	79,553	879	11,282	22,153	113,866	82,546	31,320	(2,114)
	2012	84,112	720	8,435	38,344	131,612	87,011	44,600	(2,179)
Median	2011	77,556	880	11,086	21,488	111,650	80,870	30,781	(1,793)
	2012	82,422	692	8,169	37,015	130,461	85,011	45,450	267
Standard Deviation	2011	15,931	181	2,441	5,767	20,708	16,156	4,551	(3,657)
	2012	15,855	143	1,818	7,978	17,421	16,213	1,208	(8,588)
Peak Average	2011	88,273	956	12,971	23,194	125,395	91,413	33,981	(2,184)
	2012	93,339	771	9,421	37,347	140,878	96,187	44,691	(2,076)
Peak Median	2011	84,791	972	12,747	22,802	122,634	87,930	34,705	(844)
	2012	89,430	741	9,174	36,899	138,153	92,187	45,966	(108)
Peak Standard Deviation	2011	14,784	176	1,979	5,862	18,775	14,836	3,939	(3,902)
	2012	13,984	145	1,671	5,663	14,870	14,406	464	(6,870)
Off-Peak Average	2011	71,950	812	9,809	21,245	103,815	74,815	29,000	(2,053)
	2012	76,049	676	7,574	39,215	123,515	78,994	44,521	(2,269)
Off-Peak Median	2011	70,247	819	9,571	20,472	102,274	72,658	29,617	(427)
	2012	73,982	656	7,260	37,142	121,293	76,895	44,398	(3)
Off-Peak Standard Deviation	2011	12,667	158	1,755	5,525	16,688	12,978	3,710	(3,570)
	2012	12,680	125	1,472	9,467	15,328	13,168	2,160	(8,778)

Figure 2-11 shows the average 2012 hourly cleared volume of fixed-demand bids, the sum of cleared fixed-demand and cleared price-sensitive bids, total day-ahead load and real-time load. The difference between the cleared fixed-demand and cleared price-sensitive bids and the total day-ahead load is cleared decrement bids and up-to congestion transactions.

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): 2012

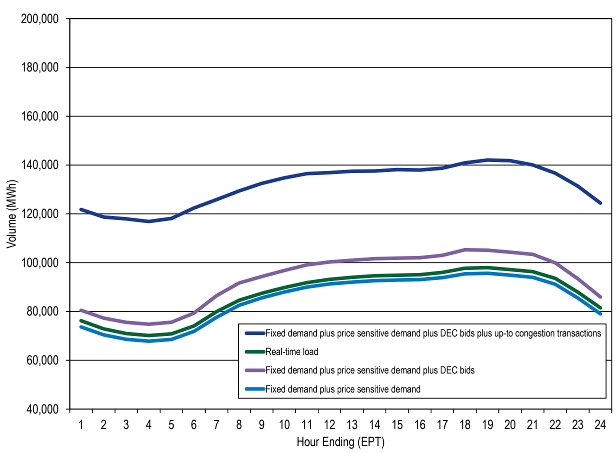
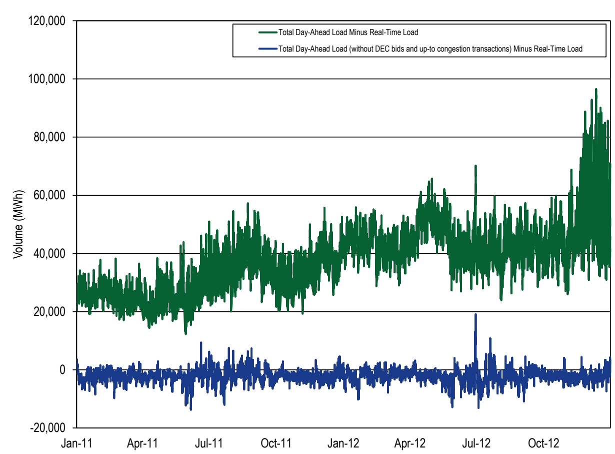


Figure 2-12 shows the difference between the day-ahead and real-time average daily loads in 2011 and 2012.

Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): 2011 and 2012



Real-Time and Day-Ahead Generation

PJM average real-time generation in 2012 increased by 3.4 percent from 2011, from 85,775 MW to 88,708 MW. PJM average real-time generation in 2012 would have decreased 2.5 percent from 2011, from 85,755 MW to

83,630 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.[46]

PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, increased by 14.8 percent from 2011, from 117,130 MW to 134,479 MW. PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, would have increased 4.7 percent from 2011, from 117,130 MW to 122,599 MW, if the DEOK and ATSI transmission zones were excluded from the comparison.

The day-ahead generation growth was 335.3 percent higher than the real-time generation growth because of the continued growth of up-to congestion transactions. If 2012 up-to congestion transactions had been held to 2011 levels, the day-ahead generation, including INCs and up-to congestion transactions, would have increased 1.0 percent instead of 14.8 percent and day-ahead generation growth would have been 70.6 percent lower than the real-time generation growth.

Real-time generation is the actual production of electricity during the operating day. Real-time generation will always be greater than real-time load because of system losses.

In the Day-Ahead Energy Market, four types of financially binding generation offers are made and cleared:[47]

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, including a minimum amount of MWh that must run from a specific unit that also has a dispatchable component above the minimum.[48]
- **Generator Offer.** Offer to supply a schedule of MWh and the corresponding offer prices from a specific unit.
- **Increment Offer (INC).** Financial offer to supply specified MWh and the corresponding offer prices. An increment offer is a financial offer that can be submitted by any market participant.
- **Up-to Congestion Transactions.** 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.[49] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. 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 2-34 presents summary real-time generation statistics for the 10-year period from 2003 through 2012.

Table 2-34 PJM real-time average hourly generation: 2003 through 2012

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
Year	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	36,628	6,165	NA	NA
2004	51,068	13,790	39.4%	123.7%
2005	81,127	15,452	58.9%	12.0%
2006	82,780	13,709	2.0%	(11.3%)
2007	85,860	14,018	3.7%	2.3%
2008	83,476	13,787	(2.8%)	(1.7%)
2009	78,026	13,647	(6.5%)	(1.0%)
2010	82,585	15,556	5.8%	14.0%
2011	85,775	15,932	3.9%	2.4%
2012	88,708	15,701	3.4%	(1.4%)

Table 2-35 presents summary day-ahead generation statistics for the 10-year period from 2003 through 2012.

46 The ATSI zone was integrated on June 1, 2011. The DEOK zone was integrated on January 1, 2012. The ATSI zone was not included in this comparison for January through May 2011, and January through May 2012. The DEOK zone was not included in this comparison.

47 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 2012 State of the Market Report for PJM, Volume II, Section 2, "Energy Market."

48 The definition of self-scheduled is based on the PJM "eMKT User Guide" (October, 2012), pp. 41-44.

49 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

Table 2-35 PJM day-ahead average hourly generation: 2003 through 2012[50]

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	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	40,296	346	40,642	8,303	310	8,292	NA	NA	NA
2004	61,687	1,068	62,755	16,791	905	17,141	53.1%	208.9%	54.4%
2005	92,906	1,532	94,438	16,932	886	17,204	50.6%	43.5%	50.5%
2006	96,322	3,734	100,056	15,860	1,555	16,543	3.7%	143.8%	5.9%
2007	104,116	4,591	108,707	16,071	1,567	16,549	8.1%	23.0%	8.6%
2008	99,105	6,381	105,485	15,558	1,889	15,994	(4.8%)	39.0%	(3.0%)
2009	91,154	6,234	97,388	15,406	2,133	16,364	(8.0%)	(2.3%)	(7.7%)
2010	94,355	12,952	107,307	17,297	7,778	21,655	3.5%	107.8%	10.2%
2011	94,977	22,153	117,130	18,069	5,767	20,977	0.7%	71.0%	9.2%
2012	96,135	38,344	134,479	17,527	7,978	17,905	1.2%	73.1%	14.8%

Table 2-36 presents summary statistics for 2011 and 2012 for day-ahead and real-time generation.

Table 2-36 Day-ahead and real-time generation (MWh): 2011 and 2012

		Day Ahead				Real Time	Average Difference	
	Year	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	2011	86,966	8,010	22,153	117,130	85,775	1,191	31,354
	2012	90,134	6,000	38,344	134,479	88,708	1,426	45,771
Median	2011	85,218	8,006	21,488	114,938	83,986	1,232	30,952
	2012	88,404	5,976	37,015	133,376	86,513	1,891	46,863
Standard Deviation	2011	17,353	1,313	5,767	20,977	15,932	1,421	5,045
	2012	17,301	922	7,978	17,905	15,701	1,600	2,203
Peak Average	2011	96,750	8,859	23,194	128,803	94,275	2,475	34,528
	2012	100,130	6,348	37,347	143,825	97,134	2,996	46,691
Peak Median	2011	93,363	8,753	22,802	126,036	90,828	2,535	35,208
	2012	96,163	6,291	36,899	141,076	93,361	2,802	47,716
Peak Standard Deviation	2011	15,502	1,048	5,862	18,954	14,683	819	4,272
	2012	15,068	753	5,663	15,219	14,272	796	947
Off-Peak Average	2011	78,437	7,271	21,245	106,953	78,365	72	28,588
	2012	81,400	5,697	39,215	126,313	81,346	55	44,967
Off-Peak Median	2011	76,403	7,217	20,472	105,400	76,383	20	29,017
	2012	79,555	5,618	37,142	124,215	79,350	205	44,865
Off-Peak Standard Deviation	2011	14,071	1,047	5,525	16,975	13,011	1,060	3,963
	2012	14,103	950	9,467	15,979	12,951	1,152	3,028

Figure 2-13 shows the average 2012 hourly cleared volumes of day-ahead generation without increment offers or up-to congestion transactions, the day-ahead generation including cleared increment bids and up-to congestion transactions and the real-time generation.[51]

50 The version of this table in the *2012 Quarterly State of the Market Report for PJM: January through March* incorrectly reported the standard deviation.
51 Generation data are the sum of MWh at every generation bus in PJM with positive output.

Figure 2-13 Day-ahead and real-time generation (Average hourly volumes): 2012

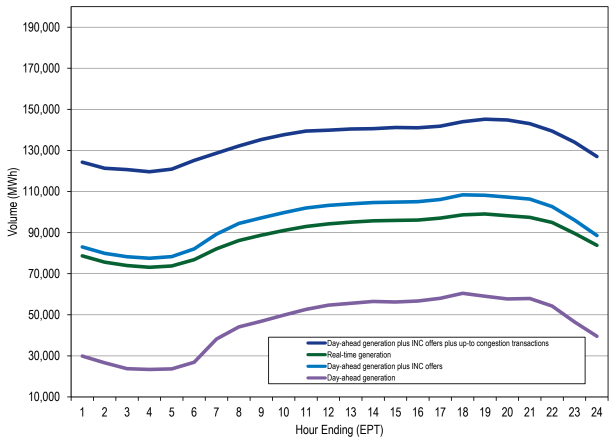
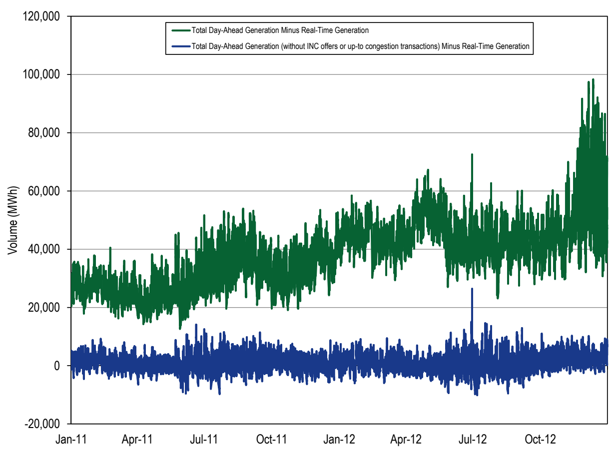


Figure 2-14 shows the difference between the day-ahead and real-time average daily generation in 2011 and 2012.

Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): 2011 and 2012



Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices.[52] 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 23.3 percent and 23.5 percent lower than in 2011 as a result of lower fuel costs and relatively low demand.[53]

PJM Real-Time Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.7 percent lower in 2012 than in 2011, $33.11 per MWh versus $42.84 per MWh. The load-weighted average LMP was 23.3 percent lower in 2012 than in 2011, $35.23 per MWh versus $45.94 per MWh.

PJM Day-Ahead Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.9 percent lower in 2012 than in 2011, $32.79 per MWh versus $42.52 per MWh. The load-weighted average LMP was 23.5 percent lower in 2012 than in 2011, $34.55 per MWh versus $45.19 per MWh.[54]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[55] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the unweighted average LMP.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-15 shows the hourly distribution of PJM real-time average LMP for 2011 and 2012.

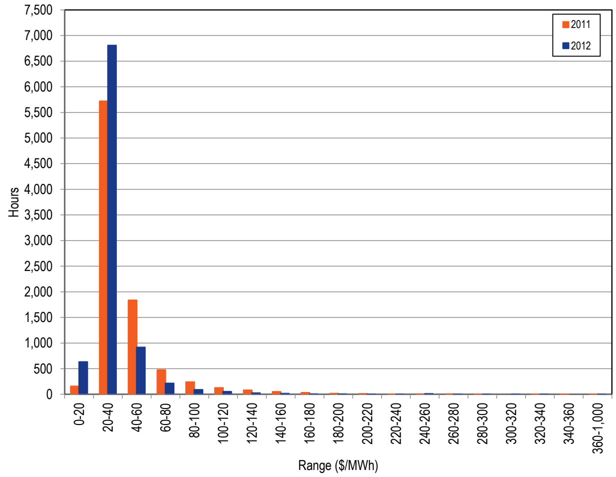
52 See the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system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

53 There was an average reduction of 1.2 heating degree days and an average increase of 0.1 cooling degree days in 2012 which meant overall reduced demand.

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

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

Figure 2-15 Average LMP for the PJM Real-Time Energy Market: 2011 and 2012



PJM Real-Time, Average LMP

Table 2-37 shows the PJM real-time, annual, average LMP for the 15-year period 1998 to 2012.[56]

Table 2-37 PJM real-time, average LMP (Dollars per MWh): 1998 through 2012

	Real-Time LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)

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.

56 The system annual, 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.

PJM Real-Time, Load-Weighted, Average LMP

Table 2-38 shows the PJM real-time, load-weighted, average LMP for the 15-year period 1998 to 2012.

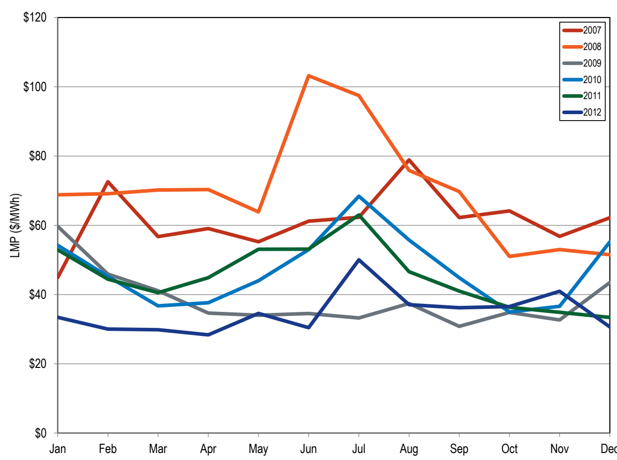
Table 2-38 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2012

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)

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

Figure 2-16 shows the PJM real-time, monthly, load-weighted LMP from 2007 through 2012.

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: 2007 through 2012



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. Both coal and natural gas decreased in price in 2012. Comparing prices in 2012 to prices in 2011, the price of Northern Appalachian coal was 16.5 percent lower; the price of Central Appalachian coal was 18.4 percent lower; the price of Powder River Basin coal was 31.5 percent lower; the price of eastern natural gas was 36.2 percent lower; and the price of western natural gas was 31.9 percent lower. Figure 2-17 shows monthly average spot fuel prices for 2011 and 2012.[57] Natural gas prices were below eastern coal prices in the months of March and April, with prices below $2/MMBtu for some days. Natural gas prices increased during summer months but remained competitive with coal on a $/MWh basis. Coal prices decreased during the year but remained relatively flat during the second half of 2012 while natural gas increased to above $3/MMBtu in the fourth quarter of 2012.

Figure 2-17 Spot average fuel price comparison: 2011 and 2012 ($/MMBtu)

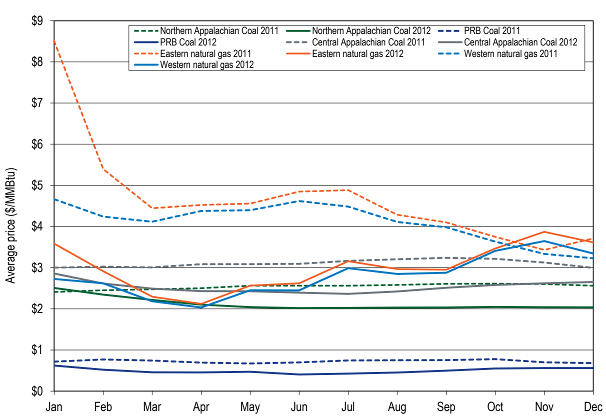


Figure 2-18 shows the average spot fuel cost of generation, comparing the fuel cost of a coal plant, combined cycle, and combustion turbine in dollars per MWh. The spot fuel cost of a new entrant combined cycle was below the spot fuel cost of a new entrant coal plant for February through June but greater for January and July through December. The average spot fuel cost of a new entrant combined cycle unit was $20.95/MWh, higher than the spot fuel cost of a new entrant coal plant, $19.60/MWh, in 2012.

In the market, new combined cycles are competing with older coal plants. Most coal plants in PJM are 20 years or older, with heat rates greater than a new coal plant. Using average heat rates for existing sub-critical coal units, the spot fuel cost of existing coal units is $23.11. Thus the spot fuel cost of new combined cycle units remains below the spot fuel cost of existing coal plants.

Figure 2-18 Average spot fuel cost of generation of CP, CT, and CC: 2011 and 2012

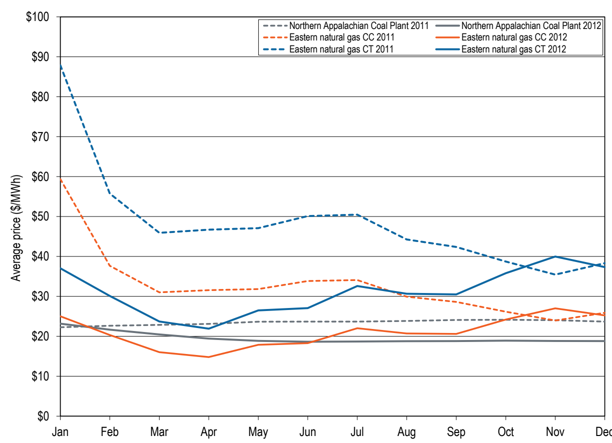


Table 2-39 compares the 2012 PJM real-time fuel cost adjusted, load weighted, average LMP to 2012 load-weighted, average LMP. The fuel cost adjusted, load weighted, average LMP for 2012 was 16.9 percent higher than the load weighted, average LMP for 2012. The real-time, fuel cost adjusted, load weighted, average LMP for 2012 was 10.4 percent lower than the load weighted LMP for 2011. If fuel costs in 2012 had been the same as in 2011, the 2012 load weighted LMP would have been higher, $41.17 per MWh instead of the observed $35.23 per MWh. The mix of fuel types and fuel costs in 2012 resulted in lower prices in 2012 than would have occurred if fuel prices had remained at their 2011 levels.

Table 2-39 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2012 Load-Weighted LMP	2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$35.23	$41.17	16.9%
	2011 Load-Weighted LMP	2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$45.94	$41.17	(10.4%)
	2011 Load-Weighted LMP	2012 Load-Weighted LMP	Change
Average	$45.94	$35.23	(23.3%)

57 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.

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.[58]

Prior to the implementation of scarcity pricing on October 1, 2012, LMPs calculated based on SCED were modified ex-post 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.

The components of LMP are shown in Table 2-40, including markup using unadjusted cost offers.[59] (Numbers in parentheses in the table are negative.) Table 2-40 shows that 53.8 percent of the annual, load-weighted LMP was the result of coal costs, 23.8 percent was the result of gas costs and 0.6 percent was the result of the cost of emission allowances. Markup was -$1.38 per MWh. In 2011, 42.2 percent of the annual, load-weighted LMP was the result of coal costs, 41.0 percent was the result of gas costs and 1.3 percent was the result of the cost of emission allowances. Markup was -$ 4.35. 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.

Table 2-40 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: 2012 and 2011

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$18.94	53.8%	$19.40	42.2%
Gas	$8.38	23.8%	$18.86	41.0%
Ten Percent Addder	$3.49	9.9%	$4.71	10.2%
VOM	$2.53	7.2%	$2.50	5.4%
Oil	$1.69	4.8%	$1.48	3.2%
NA	$1.17	3.3%	$1.99	4.3%
LPA Rounding Difference	$0.32	0.9%	($0.05)	(0.1%)
Increase Generation Adder	$0.12	0.3%	$0.21	0.5%
FMU Adder	$0.10	0.3%	$0.12	0.3%
NO_x Cost	$0.10	0.3%	$0.30	0.6%
CO_2 Cost	$0.09	0.3%	$0.29	0.6%
Market-to-Market Adder	$0.02	0.1%	($0.07)	(0.1%)
SO_2 Cost	$0.02	0.1%	$0.03	0.1%
Constraint Violation Adder	$0.02	0.1%	$0.01	0.0%
Other	$0.01	0.0%	$0.01	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Wind	($0.04)	(0.1%)	($0.05)	(0.1%)
LPA-SCED Differential	($0.12)	(0.3%)	$0.82	1.8%
Decrease Generation Adder	($0.21)	(0.6%)	($0.25)	(0.5%)
Markup	($1.38)	(3.9%)	($4.35)	(9.5%)
Total	$35.23	100.0%	$45.94	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 2-40 and Table 2-44), markup is simply the difference between the price offer and the cost offer. In the second approach (Table 2-41 and Table 2-45), 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 support this view, as the owners of coal units, facing

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

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

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 components of LMP are shown in Table 2-41, including markup using adjusted cost offers.

Table 2-41 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: 2012 and 2011

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$19.11	54.2%	$19.51	42.5%
Gas	$8.38	23.8%	$18.80	40.9%
VOM	$2.54	7.2%	$2.51	5.5%
Oil	$1.69	4.8%	$1.48	3.2%
Ten Percent Addder	$1.50	4.2%	$2.55	5.6%
NA	$1.17	3.3%	$2.15	4.7%
Markup	$0.43	1.2%	($2.42)	(5.3%)
LPA Rounding Difference	$0.32	0.9%	($0.05)	(0.1%)
Increase Generation Adder	$0.12	0.3%	$0.21	0.5%
FMU Adder	$0.10	0.3%	$0.11	0.2%
NOx Cost	$0.10	0.3%	$0.30	0.6%
CO2 Cost	$0.09	0.3%	$0.29	0.6%
Market-to-Market Adder	$0.02	0.1%	($0.07)	(0.1%)
SO2 Cost	$0.02	0.1%	$0.03	0.1%
Constraint Violation Adder	$0.02	0.1%	$0.01	0.0%
Other	$0.01	0.0%	$0.01	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Wind	($0.04)	(0.1%)	($0.05)	(0.1%)
LPA-SCED Differential	($0.12)	(0.3%)	$0.82	1.8%
Decrease Generation Adder	($0.21)	(0.6%)	($0.25)	(0.5%)
Total	$35.23	100.0%	$45.94	100.0%

Day-Ahead LMP

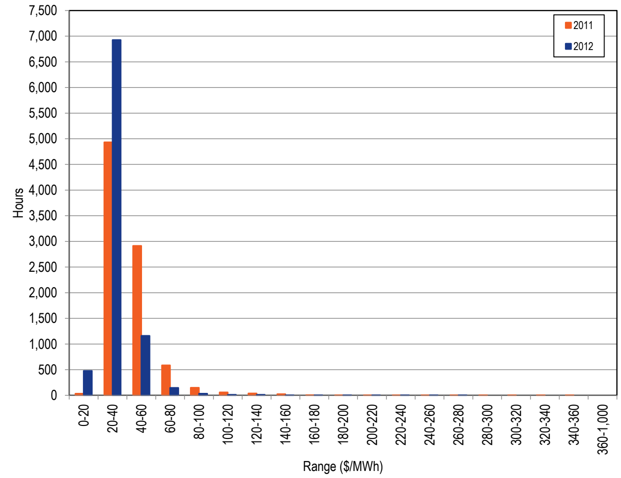
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[60] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the unweighted average LMP.

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-19 shows the hourly distribution of PJM day-ahead average LMP for 2011 and 2012.

Figure 2-19 Price for the PJM Day-Ahead Energy Market: 2011 and 2012



PJM Day-Ahead, Average LMP

Table 2-42 shows the PJM day-ahead, average LMP for the 12 year period from 2001 to 2012.

Table 2-42 PJM day-ahead, average LMP (Dollars per MWh): 2001 through 2012

	Day-Ahead LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)

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 2-43 shows the PJM day-ahead, load-weighted, average LMP for the 12 year period from 2001 to 2012.

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

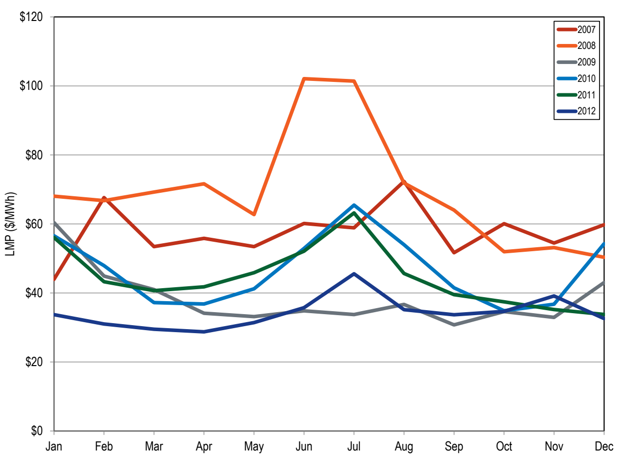
Table 2-43 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): 2001 through 2012

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)

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

Figure 2-20 shows the PJM day-ahead, monthly, load-weighted LMP from 2007 through 2012.

Figure 2-20 Day-ahead, monthly, load-weighted, average LMP: 2007 through 2012



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. Using identified marginal resource offers and the components of the 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 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.[61]

Table 2-44 shows the components of the PJM day ahead, annual, load-weighted average LMP, including markup, using unadjusted cost offers.

Table 2-44 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): 2012

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.73	39.7%	$12.65	28.0%
DEC	$8.17	23.7%	$11.21	24.8%
Gas	$4.50	13.0%	$7.68	17.0%
INC	$3.33	9.7%	$7.27	16.1%
10% Cost Adder	$2.02	5.9%	$2.23	4.9%
Up-to Congestion Transaction	$1.69	4.9%	$1.70	3.8%
VOM	$1.54	4.5%	$1.35	3.0%
Dispatchable Transaction	$0.53	1.5%	$1.41	3.1%
Price Sensitive Demand	$0.45	1.3%	$1.85	4.1%
Oil	$0.32	0.9%	$0.28	0.6%
DASR Offer Adder	$0.15	0.4%	$0.09	0.2%
CO2	$0.06	0.2%	$0.16	0.4%
NOx	$0.06	0.2%	$0.17	0.4%
SO2	$0.01	0.0%	$0.02	0.0%
FMU Adder	$0.01	0.0%	$0.02	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	($0.31)	(0.9%)	$0.52	1.2%
Markup	($1.86)	(5.4%)	($3.60)	(8.0%)
NA	$0.14	0.4%	$0.19	0.4%
Total	$34.55	100.0%	$45.19	100.0%

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

Table 2-45 shows the components of the PJM day ahead, annual, load-weighted average LMP, including markup, using adjusted cost offers.

Table 2-45 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): Calendar year 2012

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.73	39.7%	$12.65	28.0%
DEC	$8.17	23.7%	$11.21	24.8%
Gas	$4.50	13.0%	$7.68	17.0%
INC	$3.33	9.7%	$7.27	16.1%
Up-to Congestion Transaction	$1.69	4.9%	$1.70	3.8%
VOM	$1.54	4.5%	$1.35	3.0%
10% Cost Adder	$1.02	2.9%	$1.19	2.6%
Dispatchable Transaction	$0.53	1.5%	$1.41	3.1%
Price Sensitive Demand	$0.45	1.3%	$1.85	4.1%
Oil	$0.32	0.9%	$0.28	0.6%
DASR Offer Adder	$0.15	0.4%	$0.09	0.2%
CO2	$0.06	0.2%	$0.16	0.4%
NOx	$0.06	0.2%	$0.17	0.4%
SO2	$0.01	0.0%	$0.02	0.0%
FMU Adder	$0.01	0.0%	$0.02	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	($0.31)	(0.9%)	$0.52	1.2%
Markup	($0.85)	(2.5%)	($2.56)	(5.7%)
NA	$0.14	0.4%	$0.19	0.4%
Total	$34.55	100.0%	$45.19	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 each 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, decrement bids and up-to congestion transactions may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated.[62]

Table 2-46 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 March 2012.

Figure 2-21 PJM day-ahead aggregate supply curves: 2012 example day

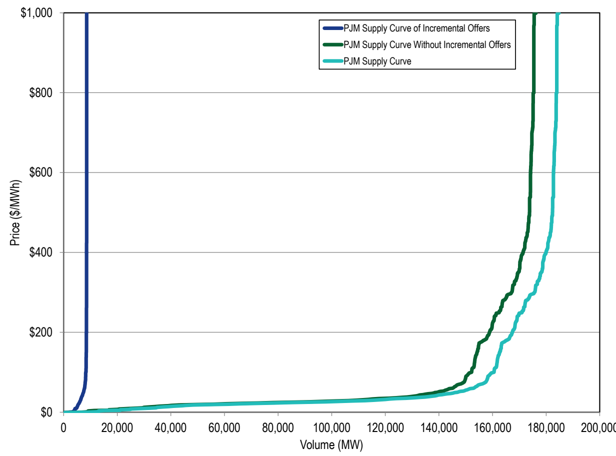


Table 2-46 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour. Table 2-47 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour. In 2012, the average submitted and cleared increment bid MW decreased 34.8 and 23.0 percent, and the average submitted and cleared decrement bid MW decreased 32.8 and 24.1 percent, compared to 2011. The 2012 average up-to congestion submitted and cleared MW increased 116.4 and 73.8 percent, compared to 2011. The increase in up-to congestion transactions displaced increment and decrement transactions.

62 An import up-to congestion transaction must source at an interface, but may sink at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. An export up-to congestion transaction may source at any hub, transmission zone, aggregate, or single bus for which LMP is calculated, but must sink at an interface. Wheeling up-to congestion transactions must both source and sink at an interface. Internal up-to congestion transactions may source or sink at any of the eligible hubs, transmission zones, aggregates, or single buses for which LMP is calculated. For a complete list of eligible locations for up-to congestion source and sink transactions see the following link from the PJM website: <http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 2-46 Hourly average volume of cleared and submitted INCs, DECs by month: 2011 and 2012

		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
2011	Jan	8,137	14,299	218	1,077	11,135	17,917	224	963
2011	Feb	8,530	16,263	215	1,672	11,071	17,355	230	1,034
2011	Mar	7,230	13,164	201	1,059	10,435	16,343	219	982
2011	Apr	7,222	12,516	185	984	10,211	16,199	202	846
2011	May	7,443	12,161	220	835	10,250	15,956	243	800
2011	Jun	8,405	14,171	238	1,084	11,648	17,542	279	1,015
2011	Jul	8,595	14,006	185	1,234	12,196	17,567	213	1,140
2011	Aug	7,540	12,349	120	1,034	10,992	15,368	161	847
2011	Sep	7,092	10,071	114	591	12,171	16,268	147	648
2011	Oct	7,726	10,242	104	351	10,983	14,550	116	396
2011	Nov	8,290	11,545	105	382	10,936	15,204	118	416
2011	Dec	8,914	12,159	107	409	11,964	15,515	114	404
2011	Annual	7,792	12,924	180	992	11,109	16,507	203	867
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

Table 2-47 Hourly average of cleared and submitted up-to congestion bids by month: 2011 and 2012

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2011	Jan	17,687	44,361	338	779
2011	Feb	17,759	48,052	386	877
2011	Mar	17,451	41,666	419	940
2011	Apr	16,114	38,182	488	1,106
2011	May	18,854	47,312	560	1,199
2011	Jun	18,323	45,802	508	1,141
2011	Jul	24,742	55,809	641	1,285
2011	Aug	28,996	60,531	654	1,348
2011	Sep	27,184	55,706	638	1,267
2011	Oct	21,985	53,830	616	1,345
2011	Nov	26,234	78,486	718	1,682
2011	Dec	29,471	94,316	720	1,837
2011	Annual	22,067	55,338	557	1,234
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

Table 2-48 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.[63]

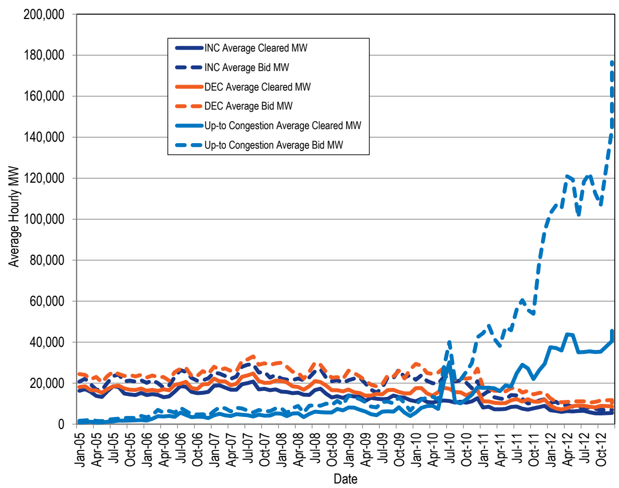
Table 2-48 Type of day-ahead marginal units: 2012

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.8%	0.1%	87.3%	5.7%	3.1%	0.1%
Feb	3.7%	0.1%	83.8%	5.4%	6.9%	0.1%
Mar	3.5%	0.1%	83.2%	6.2%	6.9%	0.1%
Apr	3.5%	0.1%	85.3%	5.2%	5.9%	0.0%
May	3.1%	0.1%	87.9%	4.6%	4.4%	0.0%
Jun	4.3%	0.0%	88.7%	4.3%	2.6%	0.0%
Jul	3.3%	0.1%	88.0%	6.1%	2.5%	0.1%
Aug	4.0%	0.1%	89.4%	4.1%	2.3%	0.0%
Sep	3.7%	0.1%	86.8%	4.5%	5.0%	0.0%
Oct	3.4%	0.1%	88.2%	4.0%	4.3%	0.0%
Nov	2.8%	0.1%	92.9%	2.0%	2.2%	0.0%
Dec	2.4%	0.0%	95.0%	1.3%	1.4%	0.0%
Annual	3.4%	0.1%	88.4%	4.3%	3.8%	0.0%

63 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

Figure 2-22 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 2-22 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through December, 2012



In order to evaluate the ownership of virtual bids, the MMU categorized 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 2-49 shows, for 2011 and 2012, the total increment offers and decrement bids by the type of parent organization: financial or physical. Table 2-50 shows for 2011 and 2012, the total up-to congestion transactions by the type of parent organization.

The top five companies with cleared up-to congestion bids are financial and account for 65.0 percent of all the cleared up-to congestion MW in PJM in 2012.

Table 2-49 PJM INC and DEC bids by type of parent organization (MW): 2011 and 2012

	2011		2012	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	125,432,065	43.0%	59,843,681	34.9%
Physical	166,308,872	57.0%	111,507,235	65.1%
Total	291,740,937	100.0%	171,350,915	100.0%

Table 2-50 PJM up-to congestion transactions by type of parent organization (MW): 2011 and 2012

	2011		2012	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	187,509,868	96.8%	318,217,668	94.7%
Physical	6,113,860	3.2%	17,660,315	5.3%
Total	193,623,729	100.0%	335,877,984	100.0%

Table 2-51 shows increment offers and decrement bids bid by top ten locations for 2011 and 2012.

Table 2-51 PJM virtual offers and bids by top ten locations (MW): 2011 and 2012

2011					2012				
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	34,784,275	39,727,544	74,511,819	WESTERN HUB	HUB	30,251,322	34,038,502	64,289,824
N ILLINOIS HUB	HUB	10,740,204	17,271,222	28,011,425	AEP-DAYTON HUB	HUB	5,095,250	6,203,179	11,298,428
AEP-DAYTON HUB	HUB	8,161,997	9,878,692	18,040,689	N ILLINOIS HUB	HUB	2,523,882	6,051,839	8,575,721
SOUTHIMP	INTERFACE	11,363,163	0	11,363,163	SOUTHIMP	INTERFACE	8,243,907	0	8,243,907
MISO	INTERFACE	292,005	8,755,249	9,047,254	MISO	INTERFACE	311,129	7,046,379	7,357,509
PECO	ZONE	2,080,316	5,855,528	7,935,844	PPL	ZONE	327,795	5,785,740	6,113,535
PPL	ZONE	318,717	4,727,485	5,046,202	PECO	ZONE	889,065	4,026,280	4,915,345
COMED	ZONE	3,208,552	243,813	3,452,365	IMO	INTERFACE	3,665,471	73,627	3,739,098
IMO	INTERFACE	2,754,598	108,998	2,863,597	BGE	ZONE	173,888	2,161,310	2,335,198
PSEG	ZONE	544,733	1,740,038	2,284,771	METED	ZONE	153,851	1,421,991	1,575,842
Top ten total		74,248,561	88,308,567	162,557,128			51,635,560	66,808,846	118,444,406
PJM total		130,593,253	161,147,684	291,740,937			73,945,975	97,404,941	171,350,915
Top ten total as percent of PJM total		56.9%	54.8%	55.7%			69.8%	68.6%	69.1%

Table 2-52 shows up-to congestion transactions by import bids for the top ten locations for 2011 and 2012.[64]

Table 2-52 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): 2011 and 2012

2011				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	N ILLINOIS HUB	HUB	3,763,388
MISO	INTERFACE	112 WILTON	EHVAGG	2,649,235
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	2,419,245
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	2,205,202
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	2,103,635
NYIS	INTERFACE	MARION	AGGREGATE	1,674,479
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	1,645,825
NYIS	INTERFACE	PSEG	ZONE	1,158,004
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,043,124
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	986,945
Top ten total				19,649,082
PJM total				104,786,982
Top ten total as percent of PJM total				18.8%
2012				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	9,190,395
OVEC	INTERFACE	DEOK	ZONE	2,413,946
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,381,726
OVEC	INTERFACE	JEFFERSON	EHVAGG	2,143,300
NYIS	INTERFACE	HUDSON BC	AGGREGATE	2,111,405
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,864,666
MISO	INTERFACE	COOK	EHVAGG	1,841,613
OVEC	INTERFACE	COOK	EHVAGG	1,785,331
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	1,784,828
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	1,686,217
Top ten total				27,203,428
PJM total				146,428,449
Top ten total as percent of PJM total				18.6%

64 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 2-53 shows up-to congestion transactions by export bids for the top ten locations for 2011 and 2012.

Table 2-53 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): 2011 and 2012

2011				
Exports				
Source	Source Type	Sink	Sink Type	MW
LUMBERTON	AGGREGATE	SOUTHEAST	AGGREGATE	6,076,609
WESTERN HUB	HUB	MISO	INTERFACE	3,932,018
23 COLLINS	EHVAGG	MISO	INTERFACE	1,684,900
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,591,281
FE GEN	AGGREGATE	SOUTHWEST	AGGREGATE	1,363,004
167 PLANO	EHVAGG	MISO	INTERFACE	1,166,857
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	1,157,710
BELMONT	EHVAGG	OVEC	INTERFACE	992,732
FOWLER 34.5 KV FWLR1AWF	AGGREGATE	OVEC	INTERFACE	969,853
RECO	ZONE	IMO	INTERFACE	847,660
Top ten total				19,782,624
PJM total				85,627,554
Top ten total as percent of PJM total				23.1%
2012				
Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	3,715,287
ROCKPORT	EHVAGG	OVEC	INTERFACE	3,343,889
23 COLLINS	EHVAGG	MISO	INTERFACE	3,085,476
STUART 1	AGGREGATE	OVEC	INTERFACE	2,386,394
GAVIN	EHVAGG	OVEC	INTERFACE	1,932,567
ROCKPORT	EHVAGG	MISO	INTERFACE	1,854,904
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,841,009
SPORN 5	AGGREGATE	OVEC	INTERFACE	1,803,365
SPORN 3	AGGREGATE	OVEC	INTERFACE	1,792,405
WESTERN HUB	HUB	MISO	INTERFACE	1,661,684
Top ten total				23,416,981
PJM total				150,988,394
Top ten total as percent of PJM total				15.5%

Table 2-54 shows up-to congestion transactions by wheel bids for the top ten locations for 2011 and 2012.

Table 2-54 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): 2011 and 2012

		2011		
		Wheels		
Source	Source Type	Sink	Sink Type	MW
CPLEIMP	INTERFACE	NCMPAEXP	INTERFACE	397,775
CPLEIMP	INTERFACE	DUKEXP	INTERFACE	287,643
NORTHWEST	INTERFACE	MISO	INTERFACE	239,020
NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	204,835
SOUTHWEST	AGGREGATE	OVEC	INTERFACE	174,891
NYIS	INTERFACE	MICHFE	INTERFACE	115,574
MISO	INTERFACE	NIPSCO	INTERFACE	114,199
NIPSCO	INTERFACE	OVEC	INTERFACE	93,186
NIPSCO	INTERFACE	MISO	INTERFACE	73,321
NCMPAIMP	INTERFACE	OVEC	INTERFACE	62,459
Top ten total				1,762,903
PJM total				3,209,193
Top ten total as percent of PJM total				54.9%
		2012		
		Wheels		
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	540,158
MISO	INTERFACE	NIPSCO	INTERFACE	198,665
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	192,006
NYIS	INTERFACE	IMO	INTERFACE	167,433
SOUTHIMP	INTERFACE	MISO	INTERFACE	149,798
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	149,407
MISO	INTERFACE	OVEC	INTERFACE	147,574
IMO	INTERFACE	NYIS	INTERFACE	138,041
NORTHWEST	INTERFACE	MISO	INTERFACE	131,420
OVEC	INTERFACE	IMO	INTERFACE	118,486
Top ten total				1,932,987
PJM total				2,974,891
Top ten total as percent of PJM total				65.0%

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.[65] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were only 4.9 percent of the PJM total internal up-to congestion transactions in 2012.

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

Table 2-55 shows up-to congestion transactions by internal bids for the top ten locations for November through December of 2012.

Table 2-55 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): November through December of 2012

2012 (November - December)				
Internal				
Source	Source Type	Sink	Sink Type	MW
NAPERVILLE	AGGREGATE	ZION 1	AGGREGATE	213,928
MARQUIS	EHVAGG	STUART DIESEL	AGGREGATE	205,066
JOLIET 8	AGGREGATE	JOLIET 7	AGGREGATE	189,609
WESTERN HUB	HUB	BGE	ZONE	174,710
SULLIVAN-AEP	EHVAGG	AK STEEL	AGGREGATE	166,152
RENO 138 KV T1	AGGREGATE	OAKGROVE 1	AGGREGATE	160,935
TANNERS CRK 4	AGGREGATE	SPORN 3	AGGREGATE	159,006
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	156,568
CONEMAUGH	EHVAGG	HUNTERSTOWN	EHVAGG	153,698
N ILLINOIS HUB	HUB	AEP-DAYTON HUB	HUB	152,976
Top ten total				1,732,647
PJM total				35,486,249
Top ten total as percent of PJM total				4.9%

Table 2-56 shows the number of source-sink pairs that were offered and cleared monthly in 2012. The increase in average offered and cleared source-sink pairs in November and December 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 more dispersion in the number of cleared up-to congestion transaction internal bids by location.

Table 2-56 Number of PJM offered and cleared source and sink pairs: 2012

2012				
Daily Number of Source-Sink Pairs				
Month	Average Offered	Max Offered	Average Cleared	Max Cleared
Jan	1,771	2,182	1,126	1,568
Feb	1,816	2,198	1,156	1,414
Mar	1,746	2,004	1,128	1,353
Apr	1,753	2,274	1,117	1,507
May	1,866	2,257	1,257	1,491
Jun	2,145	2,581	1,425	1,897
Jul	2,168	2,800	1,578	2,078
Aug	2,541	3,043	1,824	2,280
Sep	2,140	3,032	1,518	2,411
Oct	2,344	3,888	1,569	2,625
Nov	4,102	8,142	2,829	5,811
Dec	9,424	13,009	5,025	8,071
Jan-Oct	2,031	3,888	1,371	2,625
Nov-Dec	6,806	13,009	3,945	8,071

Table 2-57 and Figure 2-23 shows the spike in internal up-to congestion transactions in November and December, following the November 1, 2012, rule change permitting such transactions.

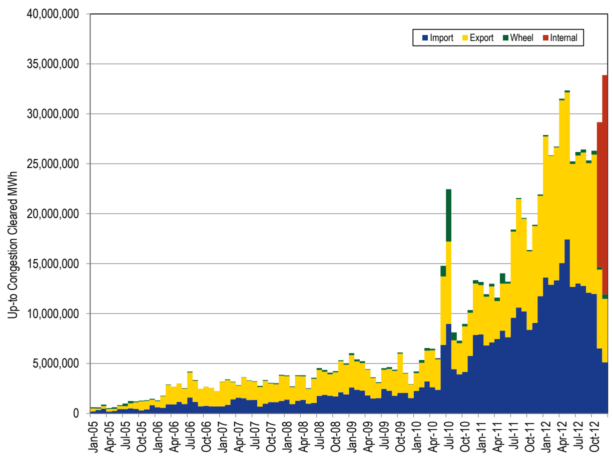
Figure 2-23 show total cleared up-to congestion transactions by type for 2011 and 2012. Internal up-to congestion transactions in just November and December of 2012, were 10.6 percent of all up-to congestion transactions for the year 2012.

Table 2-57 PJM cleared up-to congestion transactions by type (MW): 2011 and 2012

	2011				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	19,649,082	19,782,624	1,762,903	NA	20,850,203
PJM total (MW)	104,786,982	85,627,554	3,209,193	NA	193,623,729
Top ten total as percent of PJM total	18.8%	23.1%	54.9%	NA	10.8%
PJM total as percent of all up-to congestion transactions	54.1%	44.2%	1.7%	NA	100.0%
	2012				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	27,203,428	23,416,981	1,932,987	1,732,647	32,704,386
PJM total (MW)	146,428,449	150,988,394	2,974,891	35,486,249	335,877,984
Top ten total as percent of PJM total	18.6%	15.5%	65.0%	4.9%	9.7%
PJM total as percent of all up-to congestion transactions	43.6%	45.0%	0.9%	10.6%	100.0%

Figure 2-23 shows the spike in internal up-to congestion transactions in November and December, following the November 1, 2012, rule change permitting such transactions.

Figure 2-23 PJM cleared up-to congestion transactions by type (MW): 2005 through 2012



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 2-25).

Table 2-58 shows, day-ahead and real-time prices were relatively close, on average, in 2011 and 2012.

Table 2-58 Day-ahead and real-time average LMP (Dollars per MWh): 2011 and 2012[66]

	2011				2012			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$42.52	$42.84	$0.32	0.7%	$32.79	$33.11	$0.32	1.0%
Median	$38.13	$35.38	($2.75)	(7.8%)	$30.89	$29.53	($1.36)	(4.6%)
Standard deviation	$20.48	$29.03	$8.55	29.4%	$13.27	$20.67	$7.40	35.8%
Peak average	$50.45	$51.20	$0.74	1.4%	$38.46	$39.83	$1.37	3.4%
Peak median	$44.56	$40.25	($4.31)	(10.7%)	$34.71	$33.13	($1.58)	(4.8%)
Peak standard deviation	$24.60	$36.11	$11.51	31.9%	$15.86	$25.47	$9.61	37.7%
Off peak average	$35.61	$35.56	($0.05)	(0.1%)	$27.88	$27.29	($0.59)	(2.2%)
Off peak median	$32.43	$31.58	($0.85)	(2.7%)	$27.15	$26.18	($0.97)	(3.7%)
Off peak standard deviation	$12.44	$18.07	$5.63	31.2%	$7.66	$12.74	$5.08	39.9%

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

Table 2-59 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the 12-year period 2001 to 2012.

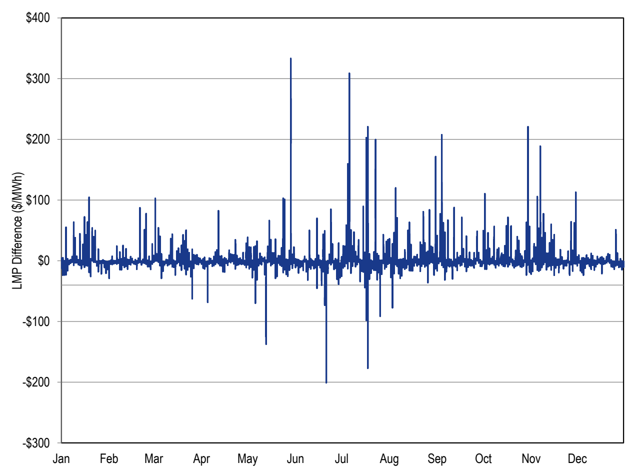
Table 2-59 Day-ahead and real-time average LMP (Dollars per MWh): 2001 through 2012

Year	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%

Table 2-60 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the years 2007 through 2012.

Figure 2-24 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in 2012.

Figure 2-24 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: 2012



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

Table 2-60 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): 2007 through 2012

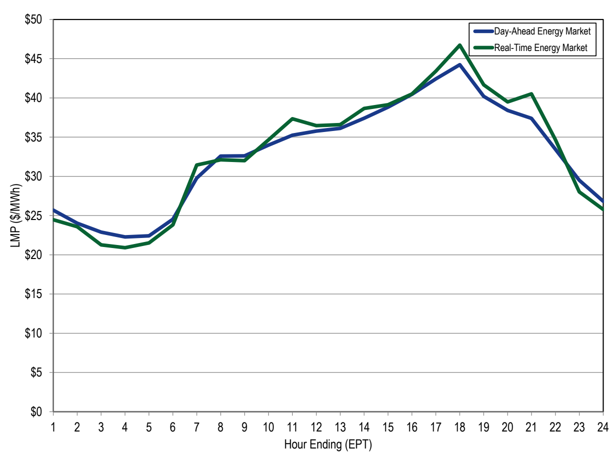
	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%	5	0.06%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%	6	0.13%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%	17	0.32%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%	5,576	63.80%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%	3,061	98.65%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%	82	99.58%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%	17	99.77%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%	12	99.91%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%	5	99.97%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%	1	99.98%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	2	100.00%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%

Figure 2-25 shows the monthly average differences between the day-ahead and real-time LMP in 2012. The figure shows a spike in the difference between the day-ahead and real-time LMP in June. A significant portion of this difference between day-ahead and real-time LMP in June was the result of relatively large differences on June 20, 21 and 29. On June 20, 21 and 29, the day-ahead market model solution required a redispatch of energy units to maintain day ahead synchronized reserves (DASR). The costs associated with the redispatch for DASR were reflected in the day-ahead energy price on these days. This cost was, in part, reflective of the lost opportunity cost (LOC) of units that were marginal for energy and DASR in the PJM market software. The LOCs caused higher than usual day-ahead versus real-time price spreads for some hours. On June 21, the day-ahead LMP was on average $50.83 more than the real-time LMP because DASR related redispatch caused day-ahead LMP to be $97.40 more than real-time LMP on average for the hours where an LOC was added to the day-ahead LMP. A similar shortage of reserves was not observed in the real-time market.

Figure 2-25 Monthly average of real-time minus day-ahead LMP: 2012

Figure 2-26 shows day-ahead and real-time LMP on an average hourly basis.

Figure 2-26 PJM system hourly average LMP: 2012



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 not generating enough power from owned plants and/or not purchasing enough power under bilateral contracts 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 2-61 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2011 and 2012 based on parent company. For 2012, 9.0 percent of real-time load was supplied by bilateral contracts, 23.2 percent by spot market purchase and 67.8 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 1.5 percentage points, reliance on spot supply decreased by 3.4 percentage points and reliance on self-supply increased by 4.9 percentage points.

Table 2-61 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2011 through 2012

	2011			2012			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	9.3%	28.8%	61.9%	8.9%	22.0%	69.1%	(0.4%)	(6.8%)	7.2%
Feb	10.9%	27.9%	61.2%	8.8%	21.2%	70.0%	(2.1%)	(6.7%)	8.7%
Mar	10.4%	29.3%	60.3%	9.4%	23.6%	67.1%	(1.0%)	(5.7%)	6.8%
Apr	10.7%	25.3%	64.1%	9.4%	23.8%	66.8%	(1.3%)	(1.4%)	2.7%
May	11.1%	25.7%	63.3%	8.6%	23.5%	67.9%	(2.6%)	(2.2%)	4.6%
Jun	10.5%	25.4%	64.1%	8.7%	22.3%	69.0%	(1.8%)	(3.1%)	4.9%
Jul	9.5%	24.7%	65.8%	8.0%	22.7%	69.3%	(1.5%)	(2.0%)	3.5%
Aug	10.3%	24.6%	65.1%	8.5%	23.6%	67.9%	(1.8%)	(1.0%)	2.8%
Sep	10.9%	26.7%	62.4%	9.1%	24.4%	66.5%	(1.9%)	(2.2%)	4.1%
Oct	12.2%	29.8%	58.0%	9.6%	25.5%	64.9%	(2.6%)	(4.3%)	6.9%
Nov	10.7%	28.3%	61.1%	9.9%	23.9%	66.3%	(0.8%)	(4.4%)	5.2%
Dec	10.1%	24.3%	65.5%	10.2%	22.6%	67.3%	0.0%	(1.7%)	1.7%
Annual	10.5%	26.6%	62.9%	9.0%	23.2%	67.8%	(1.5%)	(3.4%)	4.9%

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 2-62 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2011 and 2012, based on parent companies. For 2012, 6.7 percent of day-ahead load was supplied by bilateral contracts, 22.3 percent by spot market purchases, and 71.0 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply decreased by 2.1 percentage points, and reliance on self-supply increased by 1.3 percentage points.

Table 2-62 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2011 through 2012

	2011			2012			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.7%	23.7%	71.6%	6.6%	21.4%	72.0%	1.9%	(2.3%)	0.4%
Feb	5.4%	23.7%	70.9%	6.7%	20.0%	73.3%	1.3%	(3.7%)	2.4%
Mar	5.8%	24.3%	70.0%	6.7%	22.8%	70.5%	0.9%	(1.5%)	0.5%
Apr	6.1%	23.8%	70.1%	6.7%	22.8%	70.6%	0.6%	(1.0%)	0.5%
May	6.0%	24.0%	70.0%	6.6%	22.7%	70.7%	0.6%	(1.3%)	0.8%
Jun	6.0%	25.3%	68.8%	7.7%	20.7%	71.6%	1.8%	(4.5%)	2.8%
Jul	5.5%	23.4%	71.2%	5.9%	22.0%	72.0%	0.5%	(1.3%)	0.9%
Aug	5.7%	24.1%	70.1%	6.4%	22.5%	71.0%	0.7%	(1.6%)	0.9%
Sep	5.8%	25.2%	69.0%	6.5%	23.9%	69.6%	0.7%	(1.3%)	0.6%
Oct	5.7%	25.7%	68.5%	6.6%	25.2%	68.2%	0.8%	(0.5%)	(0.3%)
Nov	6.4%	25.3%	68.3%	6.9%	22.7%	70.5%	0.5%	(2.6%)	2.2%
Dec	6.6%	25.3%	68.1%	7.0%	21.2%	71.8%	0.3%	(4.1%)	3.8%
Annual	5.8%	24.4%	69.8%	6.7%	22.3%	71.0%	0.9%	(2.1%)	1.3%

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[67] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days may result in appropriate scarcity pricing. But this is not an efficient way to manage scarcity pricing and makes it difficult to distinguish between market power and scarcity pricing.

The energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. This is the rationale for administrative scarcity pricing mechanisms such as PJM's Reliability Pricing Model (RPM) market for capacity and PJM's administrative scarcity pricing mechanism in the energy market prior to October 1, 2012.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. In times of reserve shortage, the cost of foregone reserves, reflected as a penalty factor in the optimization, is reflected in the price of energy.

PJM did not declare an administrative scarcity event in 2012. PJM's market did not experience any reserve-based shortage events in 2012.

Designation of Maximum Emergency MW

During extreme system conditions, when PJM declares Maximum Emergency Alerts the PJM tariff specifies that capacity can only be designated as maximum emergency if the capacity has limitations on its availability based on environmental limitations, short term fuel limitations, or emergency conditions at the unit, or the additional capacity is obtained by operating the unit past its normal limits.[68,69] The intent of the rule regarding maximum emergency designation is to ensure that only capacity with a clearly defined short term issue limiting its economic availability is defined as maximum emergency MW, which can be made available, at PJM direction, to maintain the system during emergency conditions.

67 See *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market" at Figure 2-1, "Average PJM aggregate supply curves: Summers 2011 and 2012."

68 OA Schedule § 1.10.1A(d); See also PJM.

69 OA Schedule § 1.10.1A(d).

Declarations of Hot/Cold Weather Alerts also affect declarations of maximum emergency capacity under the rules. Hot Weather Alerts indicate that the system is expected to experience possible resource adequacy issues in the declared areas due to an expectation of multiple consecutive days with projected temperatures in excess of 90 degrees with high humidity.[70] Cold Weather Alerts indicate that the system is expected to experience possible resource adequacy issues in the declared areas due to an expectation that temperatures will fall below ten degrees Fahrenheit.[71] A Hot/Cold Weather Alert indicates conditions that require that combustion turbine (CT) and steam units with limited fuel availability need to be removed from economic availability and made available as emergency only capacity.[72] The Hot/Cold weather alert rule defines specific criteria to use to determine fuel limited generation, thereby classifying that part of the capacity of a unit as Maximum Emergency Generation. The Hot/Cold Weather Alert rule regarding Maximum emergency capacity declarations, as outlined in Manual 13, is consistent with the Maximum Emergency Alert rule and its intent.[73]

The indicated references are the only place in the PJM rules and tariff that there is a clear definition of maximum emergency status. The analysis suggests that some MW are inappropriately designated as maximum emergency outside of Maximum Emergency Alerts and Hot/Cold Weather Alerts. Such designations could be considered a form of withholding.

There are incentives to keep capacity incorrectly designated as maximum emergency. Capacity designated as maximum emergency is considered as available, not on outage, even during the peak five hundred hours of the year defined in RPM. Capacity designated as maximum emergency is substantially less likely to be dispatched than capacity with an economic offer on high load days.

Given the incentives to keep capacity incorrectly designated as maximum emergency under normal system conditions, the rules regarding maximum emergency designations are expected to result in a net decrease in the level of capacity designated as maximum emergency during Maximum Emergency Alerts. This is the case because MW designated as maximum emergency, which do not have to meet a clear standard at other times, must comply with the tariff definition of maximum emergency during Maximum Emergency Alerts. Capacity which was designated as maximum emergency prior to a declaration of Maximum Emergency Alerts but which does not meet this tariff definition be reported as on forced outage or as available economic capacity after such a declaration.

High Load Conditions

PJM's administrative scarcity pricing mechanism was designed to recognize real- time scarcity in the Energy Market and to increase prices to reflect the scarcity conditions. Prior to October 1, 2012 administrative scarcity pricing resulted when PJM took identified emergency actions to support identified scarcity constraints. The scarcity price was based on the highest offer of an operating unit. PJM takes emergency actions on a regional basis when the PJM system is running low on economic sources of energy and reserves. Such actions include voltage reductions, emergency power purchases, manual load dump, and loading of maximum emergency generation.[74,75] These do not represent all of the emergency actions that are available to PJM

70 The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days. See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p 45.

71 The purpose of the Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. As a general guide when the forecasted weather conditions approach minimum or actual temperatures for the Control Zone fall near or below ten degrees Fahrenheit. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods (refer to Inter RTO Natural Gas Coordination Procedure below). PJM will generally initiate a Cold Weather Alert on a Control Zone basis. See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p 42.

72 See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), pp 40-41. CTs burning oil, kerosene or diesel with less than 16 hours of remaining fuel are considered to be fuel limited during a Cold/Hot Weather Alert. CTs burning gas with less than 8 hours of daily fuel allowance are considered to be fuel limited during a Cold/Hot Weather Alert. Steam units with less than 32 hours of fuel in inventory are considered to be fuel limited during a Cold/Hot Weather Alert.

73 During Maximum Emergency Alert days, PJM rules limit maximum emergency declarations to capacity that falls into one of the following categories: environmentally limited, fuel limited, temporary emergency condition limited, or temporary megawatt additions. See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p 75.

74 A voltage reduction warning (not an action) is evidence that the system is running out of available resources. A voltage reduction warning "is implemented when the available synchronized reserve capacity is less than the synchronized reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a synchronized reserve status and emergency operating capacity is scheduled from adjacent systems." See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p. 26.

75 "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability." See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p. 19.

operators, but the listed steps that were defined in the PJM Tariff as the triggers for scarcity pricing events.[76]

PJM did not declare any scarcity pricing events in 2012 under PJM's emergency action based scarcity pricing rules. PJM's market did not experience any reserve-based shortage events in 2012.

Defining scarcity to exist when the demand for power exceeds the system-wide capacity available to provide both energy and 10 minute synchronized reserves, there were no scarcity events in 2012. Defining a high-load hour to exist when hourly real time demand plus the 30 minute reserve target is greater than or equal to the available within 30 minute economic supply (excluding maximum emergency MW), there were a total of 40 high-load hours in 2012. Defining a high-load day to exist when hourly total real time demand plus the 30 minute reserve target equals 96 percent or more of the within 30 minute supply (in the absence of non-market a dministrative intervention) on an hourly integrated basis over a two hour period,[77] there were seven high load days in 2012: July 5 - 7, 16 - 18 and 23.

2012 Results: High-Load Days

There was one Maximum Emergency Alert day in 2012, on July 18. Two days in 2012, July 17 and 18, had Maximum Emergency Actions which resulted in PJM direction to load maximum emergency capacity. Table 2-63 provides a description of PJM Maximum Emergency Alerts and Actions.

Table 2-64 shows the relationships among high load days, Hot Weather Alerts, Maximum Emergency Alerts and Maximum Emergency Actions in the May through September period. There were a total of 40 high-load hours in 2012. There were eight days with high load hours in 2012, one in June and seven in July. All seven days in July were high load days. In 2012, PJM declared twenty-eight Hot Weather Alerts.[78] Seven of the declared Hot Weather Alert days in July corresponded with the high load days. In 2012, PJM declared one maximum emergency alert day, which corresponded with one of the Hot Weather Alert days as well as one of the high load days, July 18.

Table 2-63 Maximum Emergency Alerts and Actions

Event	Purpose
Maximum Emergency Alert	Day ahead notice that maximum emergency generation has been called into day ahead operating capacity
Maximum Emergency Generation Action	Real time notice that maximum emergency generation may be required for system support
Emergency Mandatory Load Management Reductions (Long Lead Time)	Real time notice to participants registered in Demand Response(DR) program as Interruptible Load for Reliability(ILR) or DR resources that need between 1 to 2 hours lead time to provide load relief
Emergency Mandatory Load Management Reductions (Short Lead Time)	Real time notice to participants registered in Demand Response(DR) program as Interruptible Load for Reliability(ILR) or DR resources that need up to 1 hour lead time to provide load relief

76 See OA Schedule 1 § 2.5.

77 See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p. 11. The thirty minute reserve target used in the study is the day-ahead operating reserve target based of a percentage of Day Ahead peak load.

78 "The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days." See PJM. "Manual 13: Emergency Operations," Revision: 52 (Effective February 1, 2013), p. 45.

Table 2-64 High Load Hour, Hot Weather Alerts and Maximum Emergency Related Events: 2012

Dates	High Load Day (High Load Hours)	Hot Weather Alert	Maximum Emergency Generation Alert	Maximum Emergency Generation Action
6/18/2012		ComEd		
6/19/2012		ComEd, Western		
6/20/2012		PJM		
6/21/2012		PJM except ComEd		
6/22/2012		Dominion, Mid-Atlantic		
6/28/2012		PJM		
6/29/2012		PJM		
6/30/2012		PJM		
7/1/2012		PJM		
7/2/2012		PJM		
7/3/2012		PJM		
7/4/2012		PJM		
7/5/2012	3	PJM		
7/6/2012	7	PJM		
7/7/2012	5	PJM		
7/8/2012		BGE, Pepco, Dominion		
7/15/2012		ComEd, Dominion		
7/16/2012	4	ComEd, Mid-Atlantic, Dominion		
7/17/2012	10	PJM		PJM
7/18/2012	6	PJM	Mid-Atlantic	Mid-Atlantic
7/19/2012		Dominion		
7/23/2012	4	ComEd, Dominion		
7/24/2012		Dominion		
7/25/2012		ComEd		
7/26/2012		PJM except ComEd		
7/27/2012		Dominion, Mid-Atlantic		
8/3/2012		PJM		
8/31/2012		Dominion, Mid-Atlantic		

In general, participant behavior in the summer of 2012 was consistent with the market incentives created by the Capacity Market and Energy Market. Maximum emergency generation declarations during maximum emergency generation periods were lower than the monthly average. During days when an emergency alert was not called or an emergency action was not taken, some economic capacity was inappropriately designated as emergency MW.

The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during Maximum Emergency Events.[79]

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

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. 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 in 2012 were $648.7 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 25.6 percent, the balancing operating reserve charges proportion was 66.4 percent, the reactive services charges proportion was 8.0 percent and the synchronous condensing charges proportion was 0.02 percent.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.2001 per MWh, the balancing operating reserve reliability rates averaged $0.0245, $0.0219 and $0.1154 per MWh for the RTO, Eastern and Western Regions, the balancing operating reserve deviation rates averaged $0.8147, $0.3332 and $0.1265 per MWh for the RTO, Eastern and Western Regions. Lost opportunity cost rate averaged $1.3223 per MWh and canceled resources rate averaged $0.0235 per MWh.

- **Operating Reserve Credits.** Four operating reserve categories accounted for 97.8 percent of all operating reserve credits. Balancing generator operating reserves were 35.1 percent, lost opportunity cost were 29.5 percent, day-ahead generator operating reserves were 25.6 percent and reactive services were 7.6 percent of all credits.

Characteristics of Credits

- **Types of units.** Coal units received 74.3 percent of all day-ahead generator credits and 48.5 percent of all balancing generator credits. Wind units received 94.6 percent of all canceled resources credits. Combustion turbines and diesels received 87.3 percent of the lost opportunity cost credits. Combined cycles and coal units received 80.1 percent of all reactive services credits.

- **Economic – Noneconomic Generation.** In 2012, 84.2 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.9 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In 2012, 83.3 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 5.8 percent by transactions at hubs and 10.9 percent by transactions at interfaces.

- Generators in the Eastern Region paid 11.5 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 49.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 12.3 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 50.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- Generators paid 13.3 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.9 percent of all credits.

Load Response Resource Operating Reserves

- In 2012, 96.4 percent of the total energy revenues for end use customers for providing demand reductions as part of the Economic Load Response Program was paid as economic load response credits. The remaining 3.6 percent was operating reserve credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 22.7 percent of all credits. The top 10 organizations received 81.7 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 3720, balancing operating reserves was 3105 and lost opportunity cost HHI was 4169.
- **Day-Ahead Unit Commitment for Reliability:** On September 13, 2012, PJM increased the number and MWh of units scheduled as must run in the Day-Ahead Energy Market because the units were regularly needed for reliability in real time. PJM identified the need to schedule these units in the Day-Ahead Energy Market after determining that these units were affecting the commitment process for combustion turbines in real time. The increase in day ahead scheduling was intended to reduce the divergence between the scheduled resources in the Day-Ahead Market and the actual resources operating in the Real-Time Energy Market. The addition of units scheduled as must run in the Day-Ahead Energy Market shifted substantial operating reserve credits from the Balancing Energy Market to the Day-Ahead Energy Market. This is significant because day-ahead operating reserve charges and balancing operating reserve charges are allocated differently. FERC accepted proposed revisions to PJM's tariff and operating agreement to change the allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for reliability purposes.
- **Lost Opportunity Cost Credits:** In 2012, lost opportunity cost credits increased by $18.8 million compared to 2011. In 2012, the top three control zones receiving lost opportunity cost credits, AP, ComEd and Dominion combined for 64.4 percent of all lost opportunity cost credits, 60.3 percent of all the day-ahead generation from pool-scheduled combustion turbines and diesels, 65.8 percent of all day-ahead generation not called in real time by PJM from those unit types and 68.5 percent of all 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 2012, lost opportunity cost credits would have been reduced by $60.8 million, or 31.8 percent, if all changes proposed by the MMU had been implemented.
- **Wind Units Lost Opportunity Cost:** In 2012, lost opportunity cost credits paid to wind units would have been reduced by $3.1 million, or 65.6 percent, if all changes proposed by the MMU had been implemented.
- **Black Start and Voltage Support Units:** Certain units located in the AEP zone are relied on for their ALR blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. The MMU raised the issue that such costs should be categorized as black start costs rather than operating reserve charges. This issue was resolved in PJM's tariff and operating agreement filing with FERC.
- **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.
- **Up-to Congestion Transactions:** Up-to congestion transactions do not pay operating reserve charges despite that they affect dispatch and commitment in the Day-Ahead Energy Market. The impact of assigning operating reserve charges to up-to congestion transactions on the payments by other participants would be significant. For example, in 2012, the RTO deviation rate would have been reduced by 59.3 percent if up-to congestion transactions had been included in the calculation of operating reserve charges.

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 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.

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 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.

The MMU recommends that the allocation of operating reserve charges to participants be carefully reexamined to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. 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 issue of netting using internal bilateral transactions should be addressed.

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.

Description of Operating Reserves

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the LMP, the unit's operating parameters 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, startup and no-load offers. PJM 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.

Credits and Charges Categories

Operating reserve credits include day-ahead and balancing operating reserves, reactive services and synchronous condensing categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-1 and Table 3-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 3-1 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
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
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability Balancing Operating Reserve for Deviations Balancing Local Constraint	Real-Time Load plus Export Transactions Real-Time Deviations from Day-Ahead Schedule Applicable Requesting Party	in RTO, Eastern or Western Region
Canceled Resources Lost Opportunity Cost Real-Time Import Transactions Resources Performing Annual Scheduled Black Start Tests Resources Providing Quick Start Reserve	Balancing Operating Reserve Startup Cancellation Balancing Operating Reserve Lost Opportunity Cost Balancing Operating Reserve Transaction Balancing Operating Reserve Generator Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Deviations	Real-Time Deviations from Day-Ahead Schedule	in RTO Region
Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Real-Time Deviations from Day-Ahead Schedule by RTO, Eastern or Western Region	in RTO, Eastern/ Western Region

Table 3-2 Reactive services and synchronous condensing credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:
		Reactive		
Resources Providing Reactive Service	Reactive Services Generator Reactive Services Lost Opportunity Cost Reactive Services Condensing Reactive Services Condensing Lost Opportunity Cost	→	Reactive Services Charge Reactive Services Local Constraint	Zonal Real-Time Load Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing Lost Opportunity Cost	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions

Day-Ahead Operating Reserves

Day-ahead operating reserve credits consist of make whole payments to generators, import transactions and load response in the Day-Ahead Energy Market.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports.

Balancing Operating Reserves

Balancing operating reserve credits consist of make whole and lost opportunity cost payments in the balancing market. Balancing operating reserve credits are paid to generators, import transactions and load response that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced or suspended at PJM's request for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if the real-time LMP at the import pricing point is less than the price specified in the transaction, the market participant is made whole. Balancing operating reserve credits are also paid to resources when canceled before coming online, to resources performing annual, scheduled black start tests and to resources providing quick start reserve.

The balancing operating reserve charges that result from paying the total balancing operating reserve credits are allocated daily to PJM members in different categories defined by the balancing operating reserve cost allocation rules (BORCA). The rules classify the charges as reliability and deviations. Balancing operating reserve credits paid to units that operate at a loss at the request of a third party are paid by the requesting party.

Reactive Services

Reactive service credits are paid to units for the purpose of maintaining the reactive reliability of the PJM region if such units are reduced or suspended at the request of PJM and the LMP at the unit's bus is higher than its offered price. Credits are also paid to units if their output is increased at the request of PJM for the purpose of reactive services and the offered price is higher than the LMP at the unit's bus. Synchronous condensers may receive reactive service credits by providing synchronous condensing for the purpose of maintaining reactive reliability at the request of PJM. Reactive service charges are allocated daily to real-time load in the transmission zones where the reactive service was provided.

Synchronous Condensing

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services.[1]

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions.

Balancing Operating Reserve Cost Allocation

Table 3-3 Balancing operating reserve cost allocation process

	Reliability Credits	Deviation Credits
RTO	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV
East	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

1 "Manual 28: Operating Agreement Accounting," Revision 50 (January 1, 2012).

Table 3-3 shows the process for identifying balancing operating reserves credits as related either to reliability or deviations. Such credits are assigned to units during two periods, the reliability analysis (performed after the Day-Ahead Market is cleared) and the Real-Time Market.

During PJM's reliability analysis, performed after the Day-Ahead Market is cleared, credits are allocated for conservative operations or to meet forecasted real-time load. Conservative operations mean that units are committed due to conditions that warrant noneconomic actions to ensure the maintenance of system reliability. Such conditions include hot and cold weather alerts. The resultant credits are defined as reliability credits and are allocated to real-time load plus exports. Units are also committed to operate to meet the forecasted real time load plus any operating reserve requirements in addition to the physical units committed in the Day-Ahead Market. The resultant credits are defined as deviation credits.

In the Real-Time Market, credits are also identified as related to either reliability or deviations. Credits are paid to units that are called on by PJM for reliability purposes if the LMP at the unit's bus is not greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour while the unit was running at PJM's direction. These are defined as reliability credits and are allocated to real-time load plus exports.

Credits earned by all other units operated at PJM's direction in real time where the LMP is greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour are defined as deviation credits and are allocated to real-time supply, demand, and generator deviations.

Reliability and deviations credits are categorized by region based on whether a unit was called on for a transmission constraint and the voltage level of the constraint. Credits associated with transmission constraints that are 500 kV or 765 kV are assigned to RTO credits while credits associated with constraints of all other voltages are assigned to regional credits.

Determinants and Deviation Categories

Under PJM's operating reserve rules, balancing operating reserve charges are allocated regionally. PJM defined the Eastern and Western regions, in addition to the RTO region to allocate the cost of balancing operating reserves. These regions consist of control zones, hubs and interfaces. Table 3-4 shows the composition of the Eastern and Western balancing operating reserve regions.

Table 3-4 Balancing operating reserve regions[2]

Location Type	Eastern Region	Western Region
Control Zones	AECO	AEP
	BGE	AP
	Dominion	ATSI
	DPL	ComEd
	JCPL	DAY
	Met-Ed	DEOK
	PECO	DLCO
	PENELEC	
	Pepco	
	PPL	
	PSEG	
	RECO	
Hubs	Eastern	AEP - Dayton
	New Jersey	ATSI Generators
	Western	Ohio
Interfaces	NYIS	IMO
	CLPE Exp	MISO
	CPLE Imp	NIPSCO
	Duke Exp	Northwest
	Duke Imp	OVEC
	Linden	
	NCMPA Exp	
	NCMPA Imp	
	Neptune	
	South Exp	
	South Imp	

Credits paid to generators defined to be operating for reliability purposes are charged to real-time load and exports, credits paid to generators and import transactions defined to be operating to control deviations on the system, paid for energy lost opportunity credits and paid to resources canceled before coming online are charged to deviations. Table 3-5 shows the different types of deviations.

2 Only two hubs include buses in both the eastern and western regions: the Dominion Hub and the Western Interface Hub.

Table 3-5 Operating reserve deviations

Deviations		
Day-Ahead		Real-Time
Day-Ahead Demand Bid	Demand (Withdrawal)	Real-Time Load
Day-Ahead Bilateral Sales	(RTO, East, West)	Real-Time Bilateral Sales
Day-Ahead Export Transactions		Real-Time Export Transactions
Decrement Bids		
Day-Ahead Bilateral Purchases	Supply (Injection)	Real-Time Bilateral Purchases
Day-Ahead Import Transactions	(RTO, East, West)	Real-Time Import Transactions
Increment Offers		
Day-Ahead Scheduled Generation	Generator (Unit)	Real-Time Generation

Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly basis. Supply and demand deviations are netted separately for each participant by zone, hub, or interface, and totaled for the day. Each category of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared day-ahead load plus day-ahead exports plus day-ahead bilateral sale transactions; and b) the sum of real-time load plus real-time bilateral sale transactions plus real-time exports.
- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports plus day-ahead bilateral purchase transactions; and b) the sum of the real-time bilateral purchase transactions plus real-time imports.
- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations are calculated for individual units, except where netting at a bus is permitted. A deviation from a generator may offset a deviation from another generator if they are connected to the same electrically equivalent bus, and are owned by the same participant.

Demand and supply deviations are netted by zone, hub, or interface. For example, a negative deviation at a bus can be offset by a positive deviation at another bus in the same zone.

The sum of each organization's netted deviations by control zone, hub, or interface is assigned to either the Eastern or Western Region, depending on the location of the control zone, hub, or interface. The RTO Region deviations are the sum of an organization's Eastern and Western Region deviations, plus deviations that occurred at hubs that include buses in both regions. Generating units that deviate from real-time dispatch may offset deviations by another generating unit at the same bus if that unit is electrically equivalent and owned by the same participant.

An organization's total daily balancing operating reserve charges based on deviations are the sum of the three deviation categories, by region (including the RTO), for the day, multiplied by each regional deviation rate plus lost opportunity cost and canceled resources operating reserve rates.

Operating Reserve Results

Operating Reserve Charges

Table 3-6 shows total operating reserve charges from 1999 to 2012.[3] Total operating reserve charges increased by 7.6 percent in 2012 compared to 2011, to a total of $648.7 million.

3 Table 3-6 includes all categories of charges as defined in Table 3-1 and Table 3-2 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 January 7, 2013.

Table 3-6 Total operating reserve charges: 1999 through 2012[4]

	Total Operating Reserve Charges	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing
1999	$133,897,428	NA	7.5%
2000	$216,985,147	62.1%	9.6%
2001	$284,046,709	30.9%	8.5%
2002	$273,718,553	(3.6%)	5.8%
2003	$376,491,514	37.5%	5.4%
2004	$537,587,821	42.8%	6.2%
2005	$712,601,789	32.6%	3.1%
2006	$365,572,034	(48.7%)	1.7%
2007	$503,279,869	37.7%	1.6%
2008	$474,268,500	(5.8%)	1.4%
2009	$322,729,996	(32.0%)	1.2%
2010	$622,843,365	93.0%	1.8%
2011	$603,164,922	(3.2%)	1.7%
2012	$648,728,097	7.6%	2.2%

Total operating reserve charges in 2012 were $648.7 million, up from the total of $603.2 million in 2011. Table 3-7 compares monthly operating reserve charges by category for 2011 and 2012. The increase of 7.6 percent in 2012 is comprised of a 90.2 percent increase in day-ahead operating reserve charges, a 9.2 percent decrease in balancing operating reserve charges, a 27.5 percent increase in reactive services charges and an 82.9 percent decrease in synchronous condensing charges.

Table 3-8 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 and day-ahead operating reserve charges for load response. The increase of $78.8 million in day-ahead operating reserve charges was primarily a result of PJM scheduling units for reliability purposes in the Day-Ahead Energy Market in order to reduce divergence between the scheduled resources in the Day-Ahead Energy Market and the actual resources operating in the Real-Time Energy Market.

Table 3-9 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 2012, balancing operating reserve deviation charges accounted for 80.6 percent of all balancing operating reserve charges, 0.3 percentage points higher compared to the 2011 share.

Table 3-7 Monthly operating reserve charges: 2011 and 2012[5]

	2011					2012				
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Total
Jan	$12,373,210	$47,091,369	$1,546,278	$110,095	$61,120,952	$8,311,574	$27,341,331	$2,934,337	$27,037	$38,614,279
Feb	$8,940,203	$26,607,792	$1,918,076	$140,145	$37,606,217	$5,858,308	$24,877,526	$13,108,017	$18,592	$43,862,444
Mar	$6,837,719	$23,238,170	$1,438,306	$67,337	$31,581,532	$3,852,873	$29,758,387	$6,731,994	$1,648	$40,344,903
Apr	$4,405,102	$18,782,050	$2,077,101	$39,599	$25,303,852	$2,967,302	$34,168,706	$4,521,280	$0	$41,657,289
May	$7,064,934	$43,670,945	$2,712,293	$61,801	$53,509,973	$7,956,965	$43,697,911	$5,392,428	$0	$57,047,304
Jun	$8,304,092	$59,889,850	$1,868,004	$19,118	$70,081,063	$6,974,418	$45,694,198	$5,133,009	$0	$57,801,625
Jul	$4,993,311	$103,271,978	$929,808	$281,186	$109,476,283	$11,774,314	$66,578,369	$2,960,922	$0	$81,313,605
Aug	$8,360,392	$53,820,132	$1,696,735	$104,982	$63,982,240	$8,703,915	$47,577,859	$4,112,186	$0	$60,393,960
Sep	$6,249,240	$35,297,398	$2,713,004	$44,882	$44,304,524	$28,882,469	$32,732,917	$4,458,891	$24,366	$66,098,643
Oct	$5,133,837	$18,132,328	$15,523,789	$0	$38,789,953	$22,588,209	$26,181,268	$1,253,642	$38,762	$50,061,881
Nov	$7,063,847	$19,754,264	$6,758,644	$0	$33,576,755	$18,077,440	$24,349,681	$120,820	$0	$42,547,941
Dec	$7,593,046	$24,793,125	$1,445,408	$0	$33,831,578	$40,123,845	$27,761,191	$1,061,343	$37,845	$68,984,223
Total	$87,318,931	$474,349,400	$40,627,447	$869,144	$603,164,922	$166,071,633	$430,719,346	$51,788,868	$148,250	$648,728,097
Share of Charges	14.5%	78.6%	6.7%	0.1%	100.0%	25.6%	66.4%	8.0%	0.0%	100.0%

4 The total operating reserve charges in Table 3-6 are different than the total charges published in the *2011 State of the Market Report for PJM* and previous versions because previous versions did not include operating reserve charges for load response nor reactive services charges. PJM may recalculate new settlements after the State of the Market Report is published.

5 Table 3-7 and subsequent tables do not reflect the changes in day-ahead operating reserve charges and reactive services charges for December 2012. The change in the allocation of day-ahead operating reserve charges for black start and reactive services was approved by FERC (ER13-481-000) on January 28, 2013 with an effective date of December 1, 2012.

Table 3-8 Day-ahead operating reserve charges: 2011 and 2012

Type	2011	2012	Change	2011 Share	2012 Share
Day-Ahead Operating Reserve Charges	$87,318,120	$166,053,573	$78,735,453	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$811	$18,060	$17,248	0.0%	0.0%
Total	$87,318,931	$166,071,633	$78,752,701	100.0%	100.0%

Table 3-9 Balancing operating reserve charges: 2011 and 2012

Type	2011	2012	Change	2011 Share	2012 Share
Balancing Operating Reserve Reliability Charges	$90,706,786	$75,718,815	($14,987,971)	19.1%	17.6%
Balancing Operating Reserve Deviation Charges	$380,851,385	$347,024,111	($33,827,274)	80.3%	80.6%
Balancing Operating Reserve Charges for Load Response	$162,673	$319,719	$157,046	0.0%	0.1%
Balancing Local Constraint Charges	$2,628,556	$7,656,701	$5,028,145	0.6%	1.8%
Total	$474,349,400	$430,719,346	($43,630,054)	100.0%	100.0%

Table 3-10 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve 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 2012, 55.1 percent of all balancing operating reserve deviation charges were attributable to energy lost opportunity cost, an increase of 9.8 percentage points compared to the 2011 share.

Table 3-10 Balancing operating reserve deviation charges: 2011 and 2012

Charge attributable to	2011	2012	Change	2011 Share	2012 Share
Make Whole Payments to Generators and Imports	$198,418,376	$152,411,105	($46,007,271)	52.1%	43.9%
Energy Lost Opportunity Cost	$172,412,292	$191,212,934	$18,800,642	45.3%	55.1%
Canceled Resources	$10,020,716	$3,400,071	($6,620,645)	2.6%	1.0%
Total	$380,851,385	$347,024,111	($33,827,274)	100.0%	100.0%

Table 3-11 shows the composition of the reactive services charges. Reactive services charges consist of reactive services charges attributable to make whole payments and lost opportunity cost payments to generators that run at PJM's request, plus reactive services local constraint charges attributable to generators requested by a third party to provide the service.

Table 3-11 Reactive services charges: 2011 and 2012

Type	2011	2012	Change	2011 Share	2012 Share
Reactive Services Charges	$40,627,447	$51,751,602	$11,124,155	100.0%	99.9%
Reactive Services Local Constraint Charges	$0	$37,266	$37,266	0.0%	0.1%
Total	$40,627,447	$51,788,868	$11,161,421	100.0%	100.0%

Table 3-12 and Table 3-13 show the amount and percentages of regional balancing charges allocation for 2011 and 2012. Regional balancing operating reserve charges consist of the balancing operating reserve reliability and deviation charges, since 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, resources providing quick start reserve and resources performing annual, scheduled black start tests.

In 2012, regional balancing operating reserve charges decreased by $48.8 million compared to 2011. Balancing operating reserve reliability charges decreased by $15.0 million or 16.5 percent and balancing reserve deviation charges decreased by $33.8 million or 8.9 percent. In 2012, reliability charges in the Western Region increased by $19.5 million compared to 2011, as a result of payments to units providing black start and voltage support. The remaining two reliability categories decreased by $34.5 million.

Table 3-12 Regional balancing charges allocation: 2011

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$49,430,917	10.5%	$9,996,503	2.1%	$27,029,730	5.7%	$86,457,149	18.3%
	Real-Time Exports	$2,032,752	0.4%	$589,969	0.1%	$1,626,917	0.3%	$4,249,637	0.9%
	Total	$51,463,668	10.9%	$10,586,472	2.2%	$28,656,646	6.1%	$90,706,786	19.2%
Deviation Charges	Demand	$205,564,297	43.6%	$25,067,477	5.3%	$4,385,476	0.9%	$235,017,249	49.8%
	Supply	$60,333,400	12.8%	$6,643,500	1.4%	$1,514,331	0.3%	$68,491,231	14.5%
	Generator	$69,165,480	14.7%	$6,216,435	1.3%	$1,960,990	0.4%	$77,342,904	16.4%
	Total	$335,063,177	71.1%	$37,927,411	8.0%	$7,860,797	1.7%	$380,851,385	80.8%
Total Regional Balancing Charges		$386,526,845	82.0%	$48,513,882	10.3%	$36,517,443	7.7%	$471,558,171	100%

Table 3-13 Regional balancing charges allocation: 2012

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$18,780,592	4.4%	$8,012,210	1.9%	$46,269,752	10.9%	$73,062,554	17.3%
	Real-Time Exports	$593,505	0.1%	$169,755	0.0%	$1,893,001	0.4%	$2,656,261	0.6%
	Total	$19,374,097	4.6%	$8,181,965	1.9%	$48,162,753	11.4%	$75,718,815	17.9%
Deviation Charges	Demand	$185,471,316	43.9%	$16,507,163	3.9%	$4,744,936	1.1%	$206,723,416	48.9%
	Supply	$55,888,314	13.2%	$4,579,717	1.1%	$1,255,728	0.3%	$61,723,759	14.6%
	Generator	$71,072,646	16.8%	$5,260,437	1.2%	$2,243,853	0.5%	$78,576,936	18.6%
	Total	$312,432,277	73.9%	$26,347,318	6.2%	$8,244,516	2.0%	$347,024,111	82.1%
Total Regional Balancing Charges		$331,806,374	78.5%	$34,529,283	8.2%	$56,407,269	13.3%	$422,742,926	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 3-1 for how these charges are allocated.[6]

Figure 3-1 shows the weekly weighted average day-ahead operating reserve rate for 2011 and 2012. The average rate in 2012 was $0.2001 per MWh, $0.0933 per MWh higher than the average in 2011. The highest rate occurred on October 30, when the rate reached $1.0997 per MWh, 140.4 percent higher than the $0.4574 per MWh reached during 2011, on August 27. 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 operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market.[7]

Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): 2011 and 2012

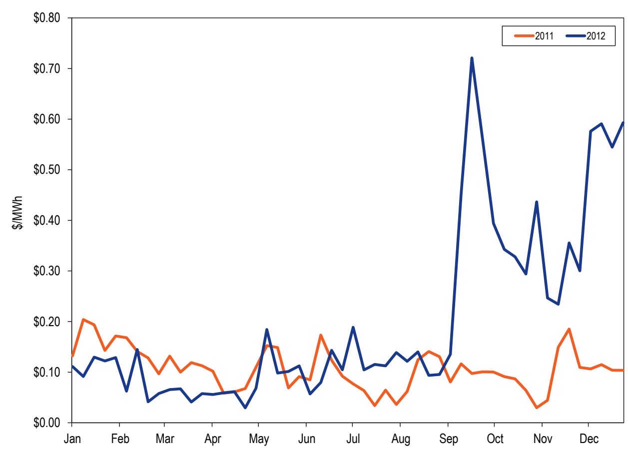


Figure 3-2 shows the RTO and the regional reliability rates for 2011 and 2012. The average daily RTO reliability rate was $0.0245 per MWh. The highest RTO reliability rate of 2012 occurred on July 18, when the rate reached $0.3160 per MWh. In 2012, reliability rates in the Eastern Region were positive for only 32 days. Hot weather related demand in the entire RTO and specifically in the Dominion control zone led to the top three Eastern Region reliability rates in 2012, on July 1, 19 and 27, the Eastern Region reliability rate reached $1.6869, $1.0099 and $1.4847 per MWh.[8] Reliability rates in the Western Region have been high primarily

6 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.

7 See "Day-Ahead Unit Commitment for Reliability" on "Operating Reserve Issues" of this section for further details on the September 13 day-ahead scheduling process change.

8 PJM issued consecutive Hot Weather Alerts for the entire RTO region for June 20 and June 21, and for June 28 through July 7, for the Dominion and Mid-Atlantic zones for June 22 and July 27 and for the Dominion zone only on July 19.

because of the use of certain units to provide black start and voltage support.

Figure 3-2 Daily balancing operating reserve reliability rates ($/MWh): 2011 and 2012

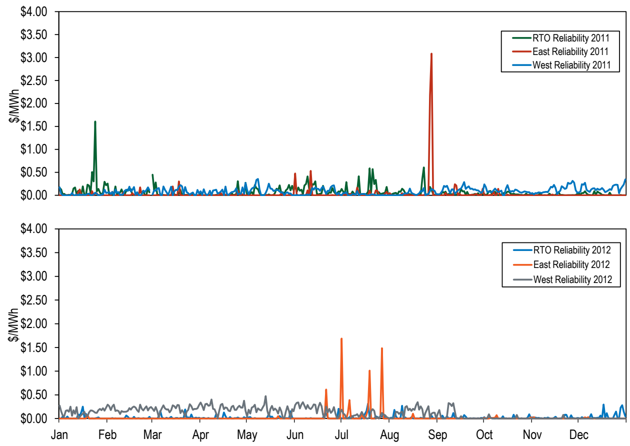


Figure 3-3 shows the RTO and the regional deviation rates for 2011 and 2012. The average daily RTO deviation rate was $0.8147 per MWh. The highest daily rate in 2012 occurred on July 26, when the RTO deviation rate reached $3.7260 per MWh.[9] The highest Eastern Region rate occurred on December 31, when a combination of transmission constraints in central and northeastern New Jersey and higher natural gas prices caused the Eastern Region rate to increase during the last days of December. Three of the top four rates occurred on the last three days of the year.[10] The Western Region deviation rate increase on April 12 was due to the loss of a 345 kV transmission line in the Pittsburgh area.

Figure 3-3 Daily balancing operating reserve deviation rates ($/MWh): 2011 and 2012

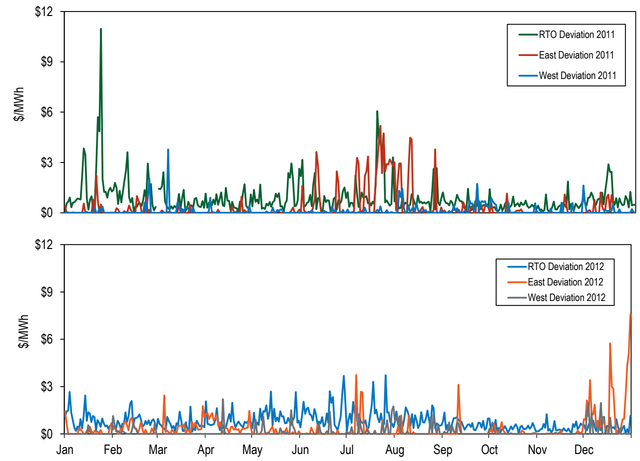
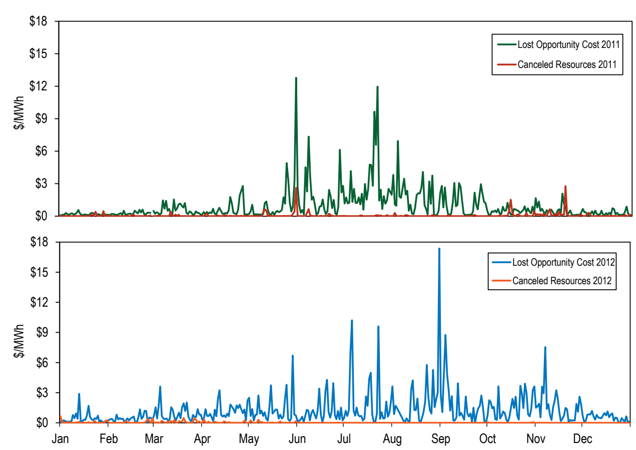


Figure 3-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2011 and 2012. The lost opportunity rate averaged $1.3223 per MWh. The highest lost opportunity cost rate occurred on August 31, when it reached $17.3678 per MWh. Increases in the lost opportunity rate are often caused by high real-time prices which increases the total lost opportunity cost credits paid to combustion turbines scheduled to run but not called in real time. The canceled resources rate averaged $0.0235 per MWh and credits were paid during 29.5 percent of all the days in 2012.

Figure 3-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2011 and 2012



9 The June 29, 2012, RTO deviation rate ($3.9347 per MWh) published in the *2012 Quarterly State of the Market Report for PJM: January through June* was higher than the July 26 rate, but the former was recalculated by PJM and resulted in a lower rate ($3.6802 per MWh).

10 Transco Zone 6 NY natural gas price index increased 313.1 percent from December 25 to December 31, 2012.

Table 3-14 shows the average rates for each region in each category for 2011 and 2012.

Table 3-14 Operating reserve rates ($/MWh): 2011 and 2012

Rate	2011 ($/MWh)	2012 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.107	0.200	0.093	87.4%
RTO Reliability	0.068	0.024	(0.044)	(64.0%)
East Reliability	0.027	0.022	(0.006)	(20.2%)
West Reliability	0.078	0.115	0.038	48.9%
RTO Deviation	0.947	0.815	(0.132)	(13.9%)
East Deviation	0.423	0.333	(0.090)	(21.3%)
West Deviation	0.111	0.126	0.016	14.4%
Lost Opportunity Cost	1.069	1.322	0.253	23.7%
Canceled Resources	0.062	0.024	(0.039)	(62.2%)

Table 3-15 shows the operating reserve cost of a 1 MW transaction during 2012. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.5908 per MWh with a maximum rate of $17.9643 per MWh, a minimum rate of $0.4698 per MWh and a standard deviation of $1.8025 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges. Table 3-15 illustrates both the average level of operating reserve charges to transaction types but also the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 3-15 Operating reserve rates statistics ($/MWh): 2012

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	17.920	2.384	0.203	1.817
	DEC	17.964	2.591	0.470	1.802
	DA Load	1.100	0.206	0.000	0.204
	RT Load	1.690	0.040	0.000	0.144
	Deviation	17.920	2.384	0.203	1.817
West	INC	17.920	2.168	0.034	1.791
	DEC	17.964	2.375	0.409	1.760
	DA Load	1.100	0.206	0.000	0.204
	RT Load	0.473	0.142	0.000	0.110
	Deviation	17.920	2.168	0.034	1.791

Operating Reserve Determinants

Table 3-16 shows the determinants used to allocate the regional balancing operating reserve charges for 2011 and 2012. Total real-time load and real-time exports were 35,308,679 MWh or 4.7 percent higher in 2012 compared to 2011. Total deviations summed across the demand, supply, and generator categories were lower in 2012 compared to 2011 by 16,625,857 MWh or 10.3 percent.

Table 3-16 Balancing operating reserve determinants (MWh): 2011 and 2012

		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
2011	RTO	722,863,726	32,677,889	755,541,614	97,202,373	30,280,081	33,753,732	161,236,185
	East	371,881,388	13,907,374	385,788,761	57,598,072	16,595,295	15,408,788	89,602,154
	West	350,982,338	18,770,515	369,752,853	39,199,351	13,557,237	18,344,944	71,101,532
2012	RTO	764,248,367	26,601,926	790,850,293	85,045,723	26,275,437	33,289,168	144,610,329
	East	362,985,584	10,425,635	373,411,219	48,968,172	14,730,038	15,374,913	79,073,124
	West	401,262,783	16,176,291	417,439,074	35,792,061	11,477,683	17,914,255	65,183,999
Difference	RTO	41,384,641	(6,075,963)	35,308,679	(12,156,650)	(4,004,644)	(464,563)	(16,625,857)
	East	(8,895,803)	(3,481,739)	(12,377,542)	(8,629,900)	(1,865,256)	(33,875)	(10,529,031)
	West	50,280,445	(2,594,224)	47,686,221	(3,407,291)	(2,079,554)	(430,689)	(5,917,534)

Operating Reserve Credits

Table 3-17 shows the totals for each credit category for 2011 and 2012. During 2012, 66.4 percent of total operating reserve credits were in the balancing category. This percentage decreased 12.2 percentage points from the 78.6 percent in 2011.

Table 3-17 Credits by operating reserve category: 2011 and 2012

Category	Type	2011	2012	Change	Percentage Change	2011 Share	2012 Share
Day-Ahead	Generators	$87,007,258	$166,053,019	$79,045,761	90.8%	14.4%	25.6%
	Imports	$310,864	$554	($310,310)	(99.8%)	0.1%	0.0%
	Load Response	$811	$18,059	$17,248	2,126.4%	0.0%	0.0%
Balancing	Canceled Resources	$10,020,718	$3,400,074	($6,620,644)	(66.1%)	1.7%	0.5%
	Generators	$287,360,286	$227,970,357	($59,389,929)	(20.7%)	47.6%	35.1%
	Imports	$1,764,877	$159,564	($1,605,313)	(91.0%)	0.3%	0.0%
	Load Response	$162,675	$319,580	$156,904	96.5%	0.0%	0.0%
	Local Constraints Control	$2,628,556	$7,656,701	$5,028,145	191.3%	0.4%	1.2%
	Lost Opportunity Cost	$172,412,291	$191,212,932	$18,800,641	10.9%	28.6%	29.5%
Reactive Services	Local Constraints Control	$0	$37,266	$37,266	NA	0.0%	0.0%
	Lost Opportunity Cost	$2,916,878	$2,466,590	($450,288)	(15.4%)	0.5%	0.4%
	Reactive Services	$37,584,680	$49,138,977	$11,554,297	30.7%	6.2%	7.6%
	Synchronous Condensing	$125,888	$146,035	$20,147	16.0%	0.0%	0.0%
Synchronous Condensing		$869,144	$148,250	($720,894)	(82.9%)	0.1%	0.0%
Total		$603,164,928	$648,727,959	$45,563,032	7.6%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 3-18 shows the distribution of total operating reserve credits by unit type for 2012. The reduction of the price spread between natural gas and coal prices resulted in an increase in operating reserve credits paid to coal units. In 2012, 43.8 percent of all operating reserve credits paid to units were paid to coal units, 19.1 percentage points more than the share in 2011. In contrast, the share of total credits paid to gas fired combined cycles declined from 19.4 percent in 2011 to 12.2 percent in 2012.

Table 3-18 Operating reserve credits by unit type: 2011 and 2012

Unit Type	2011	2012	Change	Percentage Change	2011 Share of Credits	2012 Share of Credits
Battery	$12,488	$0	($12,488)	(100.0%)	0.0%	0.0%
Combined Cycle	$116,542,789	$79,111,224	($37,431,565)	(32.1%)	19.4%	12.2%
Combustion Turbine	$233,626,148	$227,502,167	($6,123,981)	(2.6%)	38.9%	35.1%
Diesel	$20,173,863	$3,615,243	($16,558,619)	(82.1%)	3.4%	0.6%
Fuel Cell	$307,331	$0	($307,331)	(100.0%)	0.1%	0.0%
Hydro	$431,172	$294,991	($136,181)	(31.6%)	0.1%	0.0%
Nuclear	$0	$1,655,968	$1,655,968	0.0%	0.0%	0.3%
Solar	$0	$0	$0	0.0%	0.0%	0.0%
Steam - Coal	$148,474,069	$283,922,818	$135,448,749	91.2%	24.7%	43.8%
Steam - Other	$72,160,635	$44,215,846	($27,944,788)	(38.7%)	12.0%	6.8%
Wind	$9,197,206	$7,911,944	($1,285,261)	(14.0%)	1.5%	1.2%
Total	$600,925,700	$648,230,202	$47,304,502	7.9%	100.0%	100.0%

Table 3-19 shows the distribution of day-ahead and balancing operating reserve credits by unit type in 2012. Coal units received 74.3 percent of the day-ahead generator credits in 2012, 22.1 percentage points higher than the share received in 2011. Coal units received 48.5 percent of the balancing generator credits in 2012, 23.6 percentage points higher than the share received in 2011. Wind units received 94.6 percent of the canceled resources credits in 2012, 2.8 percentage points higher than the share received in 2011. Combustion turbines and diesels received 87.3 percent of the lost opportunity cost credits, 0.6 percentage points higher than the share received in 2011.

Table 3-19 Operating reserve credits by unit type: 2012

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	13.2%	18.0%	2.0%	0.1%	4.1%	15.9%	0.0%
Combustion Turbine	4.4%	20.1%	2.7%	4.3%	86.6%	15.7%	100.0%
Diesel	0.0%	0.6%	0.0%	0.0%	0.6%	2.1%	0.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	0.0%	0.1%	0.8%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	74.3%	48.5%	0.0%	95.5%	4.9%	64.2%	0.0%
Steam - Others	8.1%	12.7%	0.0%	0.1%	0.4%	2.0%	0.0%
Wind	0.0%	0.0%	94.6%	0.0%	2.4%	0.0%	0.0%
Total	$166,053,019	$227,970,357	$3,400,074	$7,656,701	$191,212,932	$51,788,868	$148,250

Table 3-19 also shows the distribution of reactive service credits and synchronous condensing by unit type. In 2012, combined cycle and coal units received 80.1 percent of all reactive services credits, 37.6 percentage points higher than the share received in 2011. In contrast, combustion turbines received 15.7 percent in 2012, 36.7 percentage points lower than the share received in 2011. Synchronous condensing was only provided by combustion turbines.

Wind Unit Credits

On June 1, 2012, PJM began to correctly categorize credits paid to wind units for lost opportunity cost and not as canceled resources credits. Also on June 1, 2012, PJM implemented new lost opportunity cost credit rules for wind units. Under the new rules, lost opportunity cost credits paid to wind units are based on the lesser of the LMP desired output and the forecasted output of the unit.[11]

Credits paid to wind units decreased in 2012. In 2012, the total was $7.9 million, lower than the $9.2 million paid in 2011. Table 3-20 shows the monthly credits paid to wind units.

11 See "PJM Manual 28: Operating Agreement Accounting" Revision 56 (October 1, 2012), Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons.

Table 3-20 Operating reserve credits paid to wind units: 2011 and 2012

	2011				2012			
	Balancing Generator	Canceled Resources	Lost Opportunity Cost	Total	Balancing Generator	Canceled Resources	Lost Opportunity Cost	Total
Jan	$0	$468,059	$0	$468,059	$0	$741,979	$0	$741,979
Feb	$0	$182,151	$0	$182,151	$0	$517,612	$0	$517,612
Mar	$0	$344,622	$0	$344,622	$0	$1,098,130	$72	$1,098,202
Apr	$0	$271,810	$0	$271,810	$20,990	$409,047	$0	$430,038
May	$0	$2,446,129	$0	$2,446,129	$23,212	$448,836	$0	$472,048
Jun	$0	$839,074	$0	$839,074	$817	$0	$119,146	$119,963
Jul	$0	$167,310	$0	$167,310	$129	$0	$63,805	$63,934
Aug	$0	$244,935	$0	$244,935	$0	$0	$175,321	$175,321
Sep	$0	$151,194	$0	$151,194	$683	$0	$834,466	$835,149
Oct	$0	$1,325,128	$0	$1,325,128	$229	$0	$2,799,801	$2,800,030
Nov	$0	$2,336,582	$0	$2,336,582	$0	$0	$215,730	$215,730
Dec	$0	$420,210	$0	$420,210	$503	$0	$441,436	$441,938
Total	$0	$9,197,206	$0	$9,197,206	$46,562	$3,215,605	$4,649,777	$7,911,944

The AEP, AP, ComEd and PENELEC Control Zones are the only zones with wind units receiving operating reserve credits.

Economic and Noneconomic Generation[12]

Economic dispatch 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 3-21 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 economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based solely on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. 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 additional hourly no load 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. In 2012, 34.5 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 32.3 percent of the real-time generation was eligible for balancing operating reserve credits.

Table 3-21 Day-ahead and real-time generation (GWh): 2012

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	798,561	275,368	34.5%
Real-Time	790,090	255,489	32.3%

Table 3-22 shows PJM's economic and noneconomic generation eligible for operating reserve credits. In 2012, 84.2 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.9 percent of the real-time generation eligible for operating reserve credits was economic.

12 The analysis of economic and noneconomic generation in previous *State of the Market Reports for PJM* was based on the relationship between the units' hourly average incremental offer and the LMP at the units' bus. The new analysis is based on the units' incremental offer, the value used by PJM to calculate LMP. Neither analysis includes no load or startup cost.

Table 3-22 Day-ahead and real-time economic and noneconomic generation (GWh): 2012

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	231,880	43,488	84.2%	15.8%
Real-Time	170,886	84,603	66.9%	33.1%

Table 3-23 shows the generation receiving day-ahead and balancing operating reserve credits. In 2012, 8.6 percent of the day-ahead generation eligible for operating reserve credits was made whole and 8.9 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 3-23 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2012

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	275,368	23,753	8.6%
Real-Time	255,489	22,810	8.9%

Geography of Charges and Credits

Table 3-24 shows the geography of charges and credits in 2012. Table 3-24 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 and synchronous condensing are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub 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, the transactions in the AEP Control Zone paid 13.0 percent of all operating reserve charges allocated regionally, and resources in the AEP Control Zone were paid 18.5 percent of the corresponding credits. The AEP Control Zone received more operating reserve credits than operating reserve charges paid. The JCPL Control Zone received fewer operating reserve credits than operating reserve charges paid. Table 3-24 also shows that 83.3 percent of all charges were allocated in control zones, 5.8 percent in hubs and 10.9 percent in interfaces.

Table 3-25 and Table 3-26 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 3-25 shows that on average, 11.5 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 49.4 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-26 also shows that generators in the Western Region paid 12.3 percent of the RTO and Western Region balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 50.5 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-24 Geography of regional charges and credits: 2012[13]

Location		Charges	Credits	Balance	Shares: Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$6,949,637	$5,214,973	($1,734,663)	1.2%	0.9%	0.9%	0.0%
	AEP	$76,374,859	$108,712,796	$32,337,937	13.0%	18.5%	0.0%	16.3%
	AP - DLCO	$45,365,789	$44,074,231	($1,291,559)	7.7%	7.5%	0.7%	0.0%
	ATSI	$36,554,526	$56,654,867	$20,100,341	6.2%	9.6%	0.0%	10.2%
	BGE - Pepco	$45,732,823	$100,073,174	$54,340,351	7.8%	17.0%	0.0%	27.4%
	ComEd - External	$73,457,999	$47,580,426	($25,877,573)	12.5%	8.1%	13.1%	0.0%
	DAY - DEOK	$27,561,044	$3,942,821	($23,618,224)	4.7%	0.7%	11.9%	0.0%
	Dominion	$42,165,186	$77,116,238	$34,951,052	7.2%	13.1%	0.0%	17.7%
	DPL	$13,615,194	$29,592,687	$15,977,492	2.3%	5.0%	0.0%	8.1%
	JCPL	$14,585,407	$10,546,598	($4,038,809)	2.5%	1.8%	2.0%	0.0%
	Met-Ed	$10,542,326	$3,911,509	($6,630,818)	1.8%	0.7%	3.3%	0.0%
	PECO	$26,975,046	$8,368,712	($18,606,334)	4.6%	1.4%	9.4%	0.0%
	PENELEC	$14,057,792	$17,895,187	$3,837,395	2.4%	3.0%	0.0%	1.9%
	PPL	$26,163,671	$9,219,252	($16,944,419)	4.4%	1.6%	8.6%	0.0%
	PSEG	$29,311,290	$65,732,911	$36,421,622	5.0%	11.2%	0.0%	18.4%
	RECO	$928,979	$0	($928,979)	0.2%	0.0%	0.5%	0.0%
	All Zones	$490,341,570	$588,636,382	$98,294,813	83.3%	100.0%	50.3%	100.0%
Hubs	AEP - Dayton	$6,306,595	$0	($6,306,595)	1.1%	0.0%	3.2%	0.0%
	Dominion	$712,977	$0	($712,977)	0.1%	0.0%	0.4%	0.0%
	Eastern	$1,147,014	$0	($1,147,014)	0.2%	0.0%	0.6%	0.0%
	New Jersey	$787,511	$0	($787,511)	0.1%	0.0%	0.4%	0.0%
	Ohio	$204,195	$0	($204,195)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$96,917	$0	($96,917)	0.0%	0.0%	0.0%	0.0%
	Western	$24,917,228	$0	($24,917,228)	4.2%	0.0%	12.6%	0.0%
	All Hubs	$34,172,436	$0	($34,172,436)	5.8%	0.0%	17.3%	0.0%
Interfaces	IMO	$9,746,975	$0	($9,746,975)	1.7%	0.0%	4.9%	0.0%
	Linden	$2,022,916	$0	($2,022,916)	0.3%	0.0%	1.0%	0.0%
	MISO	$14,985,788	$0	($14,985,788)	2.5%	0.0%	7.6%	0.0%
	Neptune	$919,748	$0	($919,748)	0.2%	0.0%	0.5%	0.0%
	NIPSCO	$77,651	$0	($77,651)	0.0%	0.0%	0.0%	0.0%
	Northwest	$399,144	$0	($399,144)	0.1%	0.0%	0.2%	0.0%
	NYIS	$5,793,997	$0	($5,793,997)	1.0%	0.0%	2.9%	0.0%
	OVEC	$1,730,224	$0	($1,730,224)	0.3%	0.0%	0.9%	0.0%
	South Exp	$8,613,474	$0	($8,613,474)	1.5%	0.0%	4.4%	0.0%
	South Imp	$19,992,576	$0	($19,992,576)	3.4%	0.0%	10.1%	0.0%
	All Interfaces	$64,282,493	$160,118	($64,122,375)	10.9%	0.0%	32.4%	0.0%
	Total	$588,796,500	$588,796,500	$0	100.0%	100.0%	100.0%	100.0%

Table 3-25 Monthly balancing operating reserve charges and credits to generators (Eastern Region): 2012

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$1,173,478	$234,258	$562,031	$1,969,766	$14,130,635
Feb	$733,719	$281,274	$433,268	$1,448,262	$9,874,828
Mar	$620,144	$477,947	$1,177,834	$2,275,925	$11,741,895
Apr	$803,236	$546,718	$1,263,975	$2,613,929	$17,370,555
May	$1,363,506	$73,346	$2,010,843	$3,447,695	$20,571,763
Jun	$1,917,833	$65,193	$1,644,883	$3,627,908	$22,401,191
Jul	$1,956,754	$619,582	$3,573,110	$6,149,446	$33,543,351
Aug	$1,196,561	$148,582	$2,962,588	$4,307,731	$23,754,698
Sep	$687,459	$102,742	$2,213,097	$3,003,298	$13,844,352
Oct	$493,377	$131,315	$2,559,682	$3,184,374	$11,949,583
Nov	$583,844	$39,463	$2,356,074	$2,979,381	$10,814,962
Dec	$681,196	$2,540,017	$747,471	$3,968,684	$18,781,651
East Generators Total	$12,211,107	$5,260,437	$21,504,855	$38,976,399	$208,779,464
PJM Total	$117,819,271	$26,347,318	$194,613,006	$338,779,594	$422,742,927
Share	10.4%	20.0%	11.1%	11.5%	49.4%

13 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 3-24 does not include synchronous condensing and local constraint control charges and credits since these are allocated zonally.

Table 3-26 Monthly balancing operating reserve charges and credits to generators (Western Region): 2012

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$1,309,915	$32,410	$787,486	$2,129,811	$12,526,783
Feb	$1,109,193	$282,686	$706,304	$2,098,184	$14,189,145
Mar	$827,049	$0	$1,515,079	$2,342,127	$17,113,158
Apr	$1,072,628	$139,080	$1,712,412	$2,924,120	$15,790,612
May	$1,775,248	$232,625	$2,441,429	$4,449,301	$22,299,111
Jun	$2,123,990	$128,649	$1,781,938	$4,034,577	$21,871,777
Jul	$2,165,687	$393,354	$3,850,796	$6,409,837	$32,185,306
Aug	$1,085,090	$316,063	$2,949,618	$4,350,772	$22,572,480
Sep	$738,362	$142,920	$2,289,074	$3,170,355	$18,572,971
Oct	$583,882	$77,826	$2,492,165	$3,153,874	$14,148,780
Nov	$478,365	$14,384	$1,889,622	$2,382,371	$13,431,833
Dec	$762,977	$483,855	$908,375	$2,155,207	$8,923,484
West Generators Total	$14,032,386	$2,243,853	$23,324,298	$39,600,537	$213,625,441
PJM Total	$117,819,271	$8,244,516	$194,613,006	$320,676,793	$422,742,927
Share	11.9%	27.2%	12.0%	12.3%	50.5%

Table 3-27 shows that on average in 2012, generator charges were 13.3 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 0.8 percentage points lower than the average for 2011. Generators received 99.9 percent of all operating reserve credits, while the remaining 0.1 percent were credits paid to import transactions and load response resources.

Table 3-27 Percentage of unit credits and charges of total credits and charges: 2011 and 2012

	2011		2012	
	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	11.2%	99.2%	11.7%	99.9%
Feb	11.8%	98.7%	11.9%	100.0%
Mar	12.9%	98.6%	14.1%	99.8%
Apr	15.5%	99.0%	15.3%	100.0%
May	16.0%	100.0%	15.5%	100.0%
Jun	13.4%	99.8%	14.9%	99.9%
Jul	16.6%	100.0%	16.2%	99.8%
Aug	14.2%	100.0%	15.7%	99.9%
Sep	13.1%	99.9%	10.1%	100.0%
Oct	11.3%	99.8%	13.0%	99.9%
Nov	12.8%	99.6%	12.6%	99.8%
Dec	11.4%	99.9%	9.0%	100.0%
Average	14.2%	99.6%	13.3%	99.9%

Reactive services charges are allocated by zone. In 2012, the top three zones accounted for 52.2 percent of the total reactive services charges and 62.5 percent of the total reactive services credits costs, a decrease of 23.2 and 21.4 percentage points from the share of the top three zones in 2011. The top three control zones in 2012 were DPL, ATSI and PENELEC.[14]

Synchronous condensing charges are allocated by zone. Two zones accounted for all synchronous condensing costs in 2012.[15]

14 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).

15 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).

Load Response Resource Operating Reserves

Load response resources participating in the Economic Load Response Program may receive make whole payments when their energy revenues from the Economic Load Program do not cover their offer plus shutdown costs.[16] These make whole payments are called load response resource operating reserve credits. Load response resources are eligible to receive operating reserve credits if they followed PJM dispatch instruction in real time. Load response resources are considered to be following dispatch if the actual load reduction does not deviate by more than 20 percent from the desired reduction.

Load response resources receive day-ahead operating reserve credits when their revenues are lower than their offer plus shutdown costs and their offer is equal or greater than the threshold price established under the Net Benefits Test. Load response resources are eligible for day-ahead operating reserve credits if they followed PJM dispatch instruction in real time.

In the Balancing Energy Market, the revenues for reducing load are based on the actual MWh reduction in excess of the scheduled day-ahead load reductions plus an adjustment for losses times the real-time LMP. Load response resources receive balancing operating reserve credits when their revenues are lower than their offer plus shutdown costs and their offer is equal or greater than the threshold price established under the Net Benefits Test. Load response resources are eligible for balancing operating reserve credits if they followed PJM dispatch instruction in real time.

In 2012, 96.4 percent of the total energy revenues of end use customers for providing demand reductions as part of the Economic Load Response Program was paid as economic load response credits. The remaining 3.6 percent was made whole through operating reserve credits as shown in Table 3-28.

Table 3-28 Day-ahead and balancing operating reserve for load response credits: 2011 and 2012

	2011				2012			
	Economic Program Credits	Operating Reserve Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve	Economic Program Credits	Operating Reserve Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve
Jan	$140,236	$1,111	99.2%	0.8%	$8,711	$19,002	31.4%	68.6%
Feb	$88,599	$0	100.0%	0.0%	$14,994	$7,878	65.6%	34.4%
Mar	$11,469	$0	100.0%	0.0%	$6,749	$56,130	10.7%	89.3%
Apr	$37,533	$17,796	67.8%	32.2%	$195,598	$0	100.0%	0.0%
May	$271,955	$130,162	67.6%	32.4%	$484,756	$0	100.0%	0.0%
Jun	$906,532	$3,932	99.6%	0.4%	$1,454,811	$30,848	97.9%	2.1%
Jul	$379,570	$539	99.9%	0.1%	$3,771,027	$169,955	95.7%	4.3%
Aug	$87,943	$191	99.8%	0.2%	$1,538,545	$35,128	97.8%	2.2%
Sep	$19,670	$0	100.0%	0.0%	$704,712	$13,346	98.1%	1.9%
Oct	$48,863	$857	98.3%	1.7%	$609,844	$29	100.0%	0.0%
Nov	$15,524	$0	100.0%	0.0%	$363,245	$5,319	98.6%	1.4%
Dec	$45,102	$8,898	83.5%	16.5%	$6,437	$4	99.9%	0.1%
Total	$2,052,996	$163,487	92.6%	7.4%	$9,159,429	$337,639	96.4%	3.6%

Operating Reserve Issues

Concentration of Operating Reserve Credits

There remains a high degree of concentration in the units and companies receiving operating reserve credits. This concentration appears to result from a combination of unit operating characteristics and PJM's persistent need for operating reserves in particular locations.

16 See Section 5, "Demand Response" at "Emergency Energy Payments" for the make whole payments to load response resources participating in the Emergency Load Response Program.

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, but decreased in 2012 compared to 2011. Table 3-29 shows the top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 22.7 percent of total operating reserve credits in 2012, compared to 28.1 percent in 2011. The top 20 units received 34.5 percent of total operating reserve credits in 2012.

Table 3-29 Top 10 operating reserve credits units (By percent of total system): 2001 through 2012

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%
2011	28.1%	0.8%
2012	22.7%	0.6%

Table 3-30 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 80.0 percent.

Table 3-30 Top 10 units and organizations operating reserve credits: 2012

		Top 10 units		Top 10 organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$75,857,182	45.7%	$158,519,962	95.5%
Balancing	Canceled Resources	$2,572,219	75.7%	$3,270,179	96.2%
	Generators	$74,128,192	32.5%	$193,659,898	84.9%
	Local Constraints Control	$7,631,871	99.7%	$7,656,701	100.0%
	Lost Opportunity Cost	$55,649,002	29.1%	$165,253,202	86.4%
Reactive Services		$34,029,951	65.7%	$46,960,654	90.7%
Synchronous Condensing		$96,664	65.2%	$148,250	100.0%
Total		$146,866,389	22.7%	$529,565,259	81.7%

Table 3-31 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2012, 48.7 percent of all credits paid to these units were allocated to deviations while the remaining 51.3 percent were paid for reliability reasons.

Table 3-31 Identification of balancing operating reserve credits received by the top 10 units by category and region: 2012

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$2,736,618	$6,677,489	$28,628,872	$32,428,073	$3,657,141	$0	$74,128,192
Share	3.7%	9.0%	38.6%	43.7%	4.9%	0.0%	100.0%

In 2012, concentration in all operating reserve credits categories was high.[17,18] Operating reserve credits HHI was calculated based on each organization's daily credits for each category. Table 3-32 shows the average HHI for each category. HHI for day-ahead operating reserve credits was 3720, for balancing operating reserve credits was 3105 and for lost opportunity cost credits was 4169.

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

18 Table 3-32 excludes the local constraints control categories.

Table 3-32 Daily operating reserve credits HHI: 2012

Category	Type	Average	Minimum	Maximum	Highest market share (One day)	Highest market share (All days)
Day-Ahead	Generators	3720	1229	10000	100.0%	33.0%
	Imports	10000	10000	10000	100.0%	60.3%
	Load Response	10000	10000	10000	100.0%	99.8%
Balancing	Canceled Resources	7101	1864	10000	100.0%	36.2%
	Generators	3105	1256	8396	91.5%	24.0%
	Imports	10000	10000	10000	100.0%	69.4%
	Load Response	9616	6957	10000	100.0%	38.4%
	Lost Opportunity Cost	4169	779	10000	100.0%	23.5%
Reactive Services		5985	1646	10000	100.0%	26.7%
Synchronous Condesing		10000	10000	10000	100.0%	100.0%
Total		1706	821	4820	68.2%	16.7%

Day-Ahead Unit Commitment for Reliability

The Day-Ahead Energy Market is solved with the objective function of minimizing the total production cost of meeting day-ahead load plus reserves subject to security constraints.[19] Under some circumstances PJM deviates from the optimal day-ahead solution when PJM is reasonably certain that specific units will be needed for reliability reasons in real time. Such actions by PJM may also be equivalent to appropriately reflecting known real time constraints in the day ahead market. PJM should be more transparent about these decisions and the reasons for them. In that case, PJM schedules the units as must run in the day ahead also. Participants can submit units as self-scheduled (must run), meaning that the unit must be committed.[20] A unit submitted as must run by a participant cannot set LMP and is not eligible for operating reserve credits. Units scheduled as must run by PJM may set LMP if raised above economic minimum and are eligible for operating reserve credits.

On September 13, PJM increased the number and MWh of units scheduled as must run in the Day-Ahead Energy Market because the units were needed for reliability in real time. PJM identified the need to schedule these units in the Day-Ahead Energy Market after determining that these units were affecting the commitment process of combustion turbines in real time. The increase in such scheduling was intended to reduce the divergence between the scheduled resources in the Day-Ahead Market and the actual resources operating in the Real-Time Energy Market. The MMU supports the concept of PJM's change in unit commitment as consistent with improved market efficiency because it appeared consistent with reflecting known real time constraints in the day ahead market. However, it would have been preferable to provide more notice to the market participants and to go through the stakeholder process to consider this change prior to implementation.

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 put such reliability issues in four categories:[21] 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.

The addition of units scheduled as must run in the Day-Ahead Energy Market shifted substantial operating reserve credits from the Balancing Energy Market to the Day-Ahead Energy Market. This is significant because day-ahead operating reserve charges and balancing operating reserve charges are allocated differently. Day-ahead operating reserve charges are paid by day-ahead load, day-ahead exports and decrement bids across the entire RTO region. Balancing operating reserve charges are paid by real-time load and real-time exports or by deviations from the day ahead depending on the allocation process. Balancing operating reserve charges are allocated across three different regions, while day-ahead operating reserve charges are not. In addition, reactive services charges in real time (attributable to units providing voltage support) are paid by real-time load on a zonal level.

19 OATT Attachment K - Appendix § 1.10.8 (a)

20 See "PJM eMkt Users Guide" Section Managing Unit Data (version June, 2012) p. 40.

21 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>.

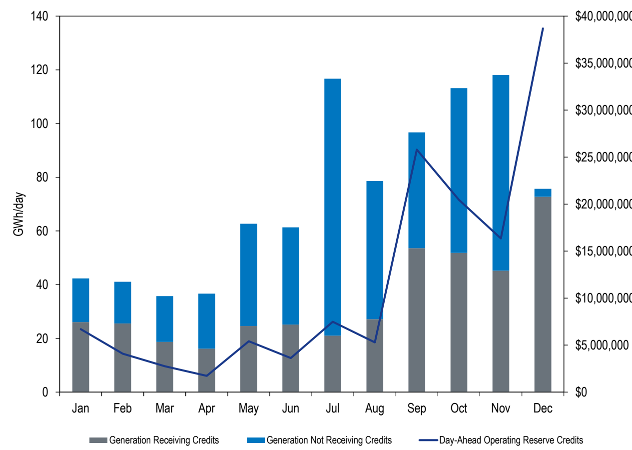
The effects of this decision on the operating reserve rates can be seen in Figure 3-1, Figure 3-2 and Figure 3-3. Figure 3-1 shows an increase in the day-ahead operating reserve rates after September 2012, and Figure 3-2 and Figure 3-3 show a decrease in the balancing operating reserve rates. Table 3-33 shows the average operating reserve rates from January 1 through September 12, 2012 and from September 13 through December 31, 2012. The average day-ahead operating reserve rate after September 13 increased by 324.3 percent compared to the average before September 13, while the average Western Region balancing operating reserve reliability rate decreased by 97.9 percent after September 13.[22]

Table 3-33 Average operating reserve rates before and after September 13, 2012

	Rate before September 13 ($/MWh)	Rate after September 13 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.104	0.443	0.338	324.3%
RTO Reliability	0.024	0.026	0.003	11.7%
East Reliability	0.029	0.003	(0.027)	(91.1%)
West Reliability	0.160	0.003	(0.156)	(97.9%)
RTO Deviations	0.964	0.428	(0.536)	(55.6%)
East Deviations	0.255	0.540	0.285	111.5%
West Deviations	0.137	0.101	(0.036)	(26.2%)
Lost Opportunity Cost	1.351	1.249	(0.102)	(7.5%)
Canceled Resources	0.032	0.002	(0.030)	(93.5%)

Figure 3-5 shows the total day-ahead generation of units scheduled as must run by PJM and the subset of generation from units scheduled as must run by PJM that received day-ahead operating reserve credits. Figure 3-5 also shows the day-ahead operating reserve credits paid to these units. November had the highest day-ahead generation from units scheduled as must run by PJM in 2012.[23] Before September 13, the average daily day-ahead generation from units scheduled as must run by PJM receiving day-ahead operating reserve credits was 23.6 GWh per day. After September 13, the daily average increased to 58.4 GWh per day. Before September 13, day-ahead operating reserve credits averaged $0.2 million per day and balancing operating reserve credits (including lost opportunity costs and canceled resources credits) averaged $1.3 million per day. After September 13 the day-ahead operating reserve credits averaged $0.9 million per day and the balancing operating reserve credits averaged $0.8 million per day. Although these results show a distinct pattern, the time periods are not strictly comparable since operating reserve credits are historically low during shoulder months.

Figure 3-5 Daily average day-ahead generation from units scheduled as must run by PJM: 2012

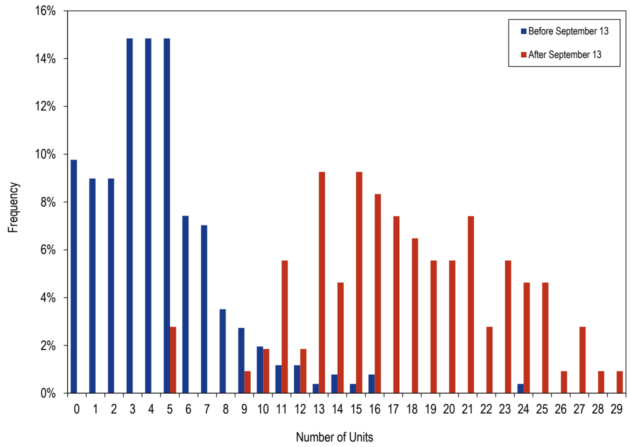


PJM scheduled an average of 9.4 units per day as must run before September 13 and on average 4.4 units received day-ahead operating reserve credits. After September 13, PJM scheduled as must run an average of 22.8 units per day and on average 17.9 units received day-ahead operating reserve credits. Figure 3-6 shows the frequency of the number of units scheduled as must run by PJM receiving day-ahead operating reserve credits before and after September 13 in 2012. For example, before September 13, three units scheduled as must run by PJM received day-ahead operating reserve credits on 14.8 percent of the days. After September 13, 13 units scheduled as must run by PJM received day-ahead operating reserve credits on 9.3 percent of the days.

22 This comparison is illustrative. The increase of the day-ahead operating reserve rate is not comparable to the decrease of the balancing operating reserve rates since the calculation of the rates have different denominators.

23 July had the second highest day-ahead generation from units scheduled as must run by PJM. PJM issued 12 hot weather alerts for the RTO region or the Mid-Atlantic region in July out of a total of 20 in 2012 for those regions.

Figure 3-6 Units scheduled as must run by PJM receiving day-ahead operating reserve credits: 2012



On October 10, 2012, PJM presented a problem statement at PJM's Market Implementation Committee (MIC) indicating the need to modify the allocation rules of day-ahead operating reserve charges as a result of the shift of balancing operating reserve charges to the Day-Ahead Energy Market.[24] Through PJM's stakeholder process two decisions were made to address the issue, both decisions were based on and consistent with the MMU recommendations:

- As a short term solution, PJM filed proposed revisions to PJM's tariff and operating agreement with FERC to change the allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for reliability purposes.[25] The proposed revisions allocated the costs of day-ahead operating reserves of units scheduled in the Day-Ahead Energy Market to provide black start service would be determined according to Schedule 6A of the OATT and the costs of day-ahead operating reserves of units scheduled in the Day-Ahead Energy Market to provide reactive service or transfer interface control would be allocated zonally in proportion to the real-time deliveries of energy to load.
- As a long term solution, a broader stakeholder process was initiated to consider market design and cost allocation issues in detail and propose OATT changes where needed.[26]

The MMU recommends PJM clearly identify and classify all reasons for incurring in operating reserves in the Day-Ahead and the Real-Time Energy Markets in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The 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

In 2012, lost opportunity cost credits increased by $18.8 million or 10.9 percent compared to 2011.

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 the Day-Ahead Energy Market but is not dispatched 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 will have to pay.[27] 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, the unit will receive a credit for lost opportunity cost based on the desired output.

On April 3, 2012, PJM implemented a new rule to reduce the unnecessary payment of operating reserve credits to combustion turbines and diesels that are committed day ahead but not dispatched in real time. Under the new rule, such units are eligible for lost opportunity cost credits only if their lead times (notification plus start time) are less than or equal to two hours.[28]

Table 3-34 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 2012, PJM scheduled 20,254 GWh from combustion

24 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>.

25 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).

26 PJM created the MIC sub group Day - Ahead (DA) Reliability and Reactive Cost Allocation (DARRCA) to address the allocation methodology of the costs of day-ahead operating reserve for reliability. <http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={323CE736-A41E-49D4-A8AF-687BB3697AE9}>.

27 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 MWh position in real time.

28 See "PJM Manual 28: Operational Agreement Accounting," Revision 56 (Effective October 1, 2012), p. 22.

turbines and diesels, of which 64.1 percent was not requested by PJM in real time and of which 53.1 percent received lost opportunity cost credits. In 2011, PJM scheduled 9,331 GWh from combustion turbines and diesels.

Table 3-34 Day-ahead generation from combustion turbines and diesels (GWh): 2011 and 2012

	2011			2012		
	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	188	66	46	572	435	373
Feb	174	75	69	753	590	546
Mar	352	232	205	1,408	1,076	921
Apr	264	121	95	1,870	1,431	1,249
May	671	472	270	1,926	1,250	1,046
Jun	1,317	713	487	2,586	1,624	1,235
Jul	2,944	1,276	878	3,898	1,424	988
Aug	1,478	765	585	2,356	1,383	1,122
Sep	775	426	342	1,635	1,169	1,032
Oct	375	261	227	1,079	895	797
Nov	454	323	252	1,319	1,018	823
Dec	339	212	151	851	678	625
Total	9,331	4,942	3,607	20,254	12,973	10,757
Share	100.0%	53.0%	38.7%	100.0%	64.1%	53.1%

In 2012, the top three control zones receiving lost opportunity cost credits, AP, ComEd and Dominion combined for 64.4 percent of all lost opportunity cost credits, 60.3 percent of all the day-ahead generation from combustion turbines and diesels, 65.8 percent of all day-ahead generation not called in real time by PJM from those unit types and 68.5 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 3-35 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 3-35 shows that $138.0 million or 72.2 percent of all lost opportunity cost credits were paid to combustion turbines and diesels that did not run for any hour in real time.

Table 3-35 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2012

	Lost Opportunity Cost Credits	
	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule
Jan	$4,857,442	$355,007
Feb	$4,382,996	$154,019
Mar	$9,661,923	$894,042
Apr	$10,846,998	$1,028,201
May	$12,925,885	$2,775,886
Jun	$12,550,655	$2,163,079
Jul	$13,911,706	$13,967,989
Aug	$22,219,006	$3,415,961
Sep	$17,783,763	$2,196,639
Oct	$11,185,166	$1,296,974
Nov	$12,704,380	$2,130,370
Dec	$4,979,204	$364,570
Total	$138,009,125	$30,742,736

PJM may not run units in real time if the real-time value of that energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 3-36 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 3-36 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 2012, 69.6 percent of the scheduled generation not called by PJM from units receiving lost opportunity cost credits was economic and the remaining 30.4 percent was noneconomic.

Table 3-36 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value[29]

	Day-Ahead Generation Not Requested in Real Time		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	309	136	445
Feb	422	248	670
Mar	805	287	1,092
Apr	1,126	329	1,455
May	875	363	1,237
Jun	835	667	1,501
Jul	826	402	1,228
Aug	946	397	1,343
Sep	880	305	1,185
Oct	710	193	903
Nov	782	280	1,062
Dec	434	298	732
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 being called in real time when they are economic.

Lost Opportunity Cost and Perfect Dispatch

PJM's Perfect Dispatch application solves the security-constrained unit commitment and dispatch problem by minimizing the total bid production cost, assuming that the real system conditions were known in advance.[30] Perfect Dispatch is a look-back application, which uses the real system conditions to solve the unit dispatch and commitment problem and to compare its solution with the actual unit dispatch and commitment. Since real conditions will never be perfectly forecasted, the Perfect Dispatch solution cannot be achieved in real time. The Perfect Dispatch solution is used by PJM as a performance index to measure the real-time operation efficiency.

The objective of Perfect Dispatch is to identify the optimal resource dispatch and commitment that does not cause reliability issues. The Perfect Dispatch application may redispatch generators (increase or decrease their output) and/or commit and decommit generators. Steam units can usually be redispatched but not committed or decommitted because of their operational parameters. Combustion turbines and diesels can usually be committed or decommitted.

In real time, total cost includes two components: the bid production cost (based on the amount of MWh delivered times the resources' committed offers plus no load and startup costs) and the lost opportunity cost paid to units scheduled in the Day-Ahead Energy Market and not called in real time. Perfect Dispatch only takes into account the first component. Without taking into account the second component, the Perfect Dispatch solution might dispatch or commit a unit in real time that could reduce the bid production cost by displacing a unit scheduled in the Day-Ahead Market. But Perfect Dispatch ignores the increase in lost opportunity cost operating reserve charges that result. Perfect Dispatch should achieve the least cost solution taking into account both components. More importantly, PJM dispatch should aim to achieve the least cost solution by accounting for the impact of dispatch decisions on operating reserve charges.

The MMU recommends including the lost opportunity costs paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not called in real time in the calculation of PJM's Perfect Dispatch. Perfect Dispatch should include the lost opportunity costs paid to these units for a proper assessment of the total cost of the system, which include the costs of not calling in real time units that were scheduled in the Day-Ahead Energy Market.

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.[31] PJM and the MMU jointly proposed two specific modifications. The MMU also believes that two additional modifications would be appropriate but the

29 The total generation in Table 3-36 is lower than the Day-Ahead Generation not requested in Real Time in Table 3-34 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 3-36 includes all generation, including generation from units that were not called in real time and did not receive lost opportunity cost credits.

30 See Gisin, B., Gu, Q. Mitsche, J., Tam, S. and Chen, H. "Perfect Dispatch as the Measure of PJM Real Time Grid Operational Performance" for a complete description of Perfect Dispatch <www.power-gem.com/Perfect_Dispatch_Paper_final.pdf>

31 See "Meeting Minutes" from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>. (April 4, 2012)

MMU has not formally recommended these to the MIC for consideration although they were brought to the attention of the MIC.

- **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' price schedule if available and the unit does not fail the TPS test.

Table 3-37 shows the impact that each of these changes would have had on the lost opportunity cost credits in the energy market for 2012, for the two categories of lost opportunity cost credits. Energy lost opportunity cost credits would have been reduced by $60.8 million, or 31.8 percent, if all these changes had been implemented.[32]

32 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 3-37 Impact on energy market lost opportunity cost credits of rule changes: 2012

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$22,461,071	$168,751,861	$191,212,932
Impact 1: Committed Schedule	$1,346,013	$33,151,094	$34,497,107
Impact 2: Eliminating DA LMP	NA	($942,269)	($942,269)
Impact 3: Using Offer Curve	($1,200,074)	$13,712,971	$12,512,897
Impact 4: Including No Load Cost	NA	($82,053,680)	($82,053,680)
Impact 5: Including Startup Cost	NA	($24,853,844)	($24,853,844)
Net Impact	$145,939	($60,985,727)	($60,839,788)
Credits After Changes	$22,607,010	$107,766,133	$130,373,144

Table 3-38 shows the impact of each of the proposed modifications made jointly by PJM and the MMU. Energy lost opportunity cost credits would have been reduced by $67.0 million, or 35.0 percent, if the two proposed modifications had been implemented.

Table 3-38 Impact on energy market lost opportunity cost credits of proposed rule changes: 2012

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$22,461,071	$168,751,861	$191,212,932
Impact 1: Committed Schedule	$1,346,013	$33,151,094	$34,497,107
Impact 2: Including No Load Cost	NA	($78,359,367)	($78,359,367)
Impact 3: Including Startup Cost	NA	($23,119,630)	($23,119,630)
Net Impact	$1,346,013	($68,327,903)	($66,981,889)
Credits After Changes	$23,807,085	$100,423,958	$124,231,043

On November 7, 2012, PJM presented proposals addressing the consistency of lost opportunity cost calculations at PJM's Market Implementation Committee (MIC). Table 3-39 summarizes the two proposals that were voted on at the MIC. The MIC favored package 3 and both proposals were forwarded to the Markets and Reliability Committee (MRC).[33] The MRC approved indefinitely postponing voting on addressing the consistency of lost opportunity cost calculations.[34]

Table 3-39 Lost opportunity cost proposals

Market / Service	Category / Type	Status Quo	Package 2	Package 3
Energy	Combustion Turbines / Engines Scheduled DA not called RT	Higher of price-based and cost-based schedule	Committed schedule	Higher of price-based and cost-based schedule
	Units reduced in RT	Higher of price-based and cost-based schedule	Committed schedule	Operating cost-based schedule
Reactive Services	Units reduced in RT	Higher of price-based and cost-based schedule	Committed schedule	Operating cost-based schedule
Ancillary Services	Regulation	Lower of price-based scheduled and the higher cost-based schedule	Committed schedule	Committed schedule when raised cost-based schedule when lowered
	Day-Ahead Scheduling Reserves	Committed schedule	Committed schedule	Committed schedule when raised cost-based schedule when lowered
	Synchonized Reserves (Tier 2)	Committed schedule	Committed schedule	Committed schedule when raised cost-based schedule when lowered
	Non Synchronized Reserves	Committed schedule	Committed schedule	Committed schedule

33 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> (Accessed January 11, 2013).

34 See "Draft Minutes," from PJM's MRC December 20, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130131/20130131-draft-minutes-mrc-20121220.ashx> (Accessed January 24, 2013).

Lost Opportunity Cost for Wind Units

Lost opportunity cost credits are paid to wind units when reduced or suspended by PJM and the real-time LMP at the units' bus is greater than the units' offer. Wind units are paid the difference between their desired and actual output, multiplied by the difference between the real-time LMP and their offer. Under the current rules, the expected output of a wind unit is based on the lesser of the desired output and the forecasted output of the unit.[35]

The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs).[36]

The MMU recommends using the estimated output of the units based on actual wind conditions at the unit, not forecasted, to calculate wind units lost opportunity costs. Lost opportunity cost credits are calculated after the operating day, therefore there is no need to use forecasted wind conditions to calculate the output wind units could have achieved.

The MMU recommends using the capacity interconnection rights (CIRs) to calculate wind units' lost opportunity cost credits. In addition, the MMU recommends that PJM allow wind units, at their discretion, to submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. CIRs are the right, in MW, capacity resources have to input power into the transmission system.[37,38]

CIRs are linked to the capacity value resources may offer in the Capacity Market. For wind units, the capacity value is limited to the amount of capacity it can reliably contribute during summer peak hours.[39] CIRs of wind units are limited to their capacity capability in the summer peak hours and not their maximum output at any time.

PJM should make a distinction between the capacity value units can inject into the transmission system (CIRs) and the capacity value that units may offer in the Capacity Market. Wind units should be compensated for LOC taking into account the capacity value used to analyze the feasibility of interconnecting the resource to the transmission system. Network resources pay the costs of interconnecting to the system in order to receive interconnection service from PJM, including any upgrades if necessary. Resources that have not paid for transmission upgrades or only paid for upgrades based on a fraction of their maximum desired output have no right to inject additional energy when it causes reliability issues.

Wind units that elect to be capacity resources must have CIRs equal to 13 percent of their maximum output, or equal to their demonstrated capacity factor during summer peak hours. PJM should allow wind units to submit CIRs reflective of their maximum desired output and perform interconnection studies based on those values. Wind units would have to pay for any transmission upgrades needed to reliably inject that additional energy.

Table 3-40 shows the impact that the MMU proposal would have had on the lost opportunity cost credits paid to wind units in the energy market in 2012. Lost opportunity cost credits paid to wind units would have been reduced by $3.1 million, or 65.6 percent, if the change had been implemented. Lost opportunity costs paid to wind units are paid by deviations in the RTO region.

Table 3-40 Impact of proposed rule change on lost opportunity cost credits paid to wind units: 2012

	Current Wind LOC Credits	Wind LOC Credits with Proposed Change	Proposed Change Impact
Jan	$0	$0	$0
Feb	$0	$0	$0
Mar	$72	$72	$0
Apr	$0	$0	$0
May	$0	$0	$0
Jun	$119,146	$30,756	($88,390)
Jul	$63,805	$40,480	($23,326)
Aug	$175,321	$73,779	($101,542)
Sep	$834,466	$360,693	($473,774)
Oct	$2,799,801	$868,636	($1,931,164)
Nov	$215,730	$101,808	($113,922)
Dec	$441,436	$121,940	($319,495)
Total	$4,649,777	$1,598,165	($3,051,613)

35 The current lost opportunity cost credits to wind units became effective on June 1, 2012.

36 This issue was raised by the MMU in the PJM Lost Opportunity Cost for Wind filing. See PJM Interconnection, L.L.C. filing in FERC Docket No. ER12-1422-000 (April 23, 2012). "Comments of the Independent Market Monitor for PJM".

37 OATT 1 Definitions § 1.3C.

38 OATT IV Interconnections with the Transmission System § 36.1A.2.

39 "Manual 21: Rules and Procedures for Determination of Generating Capability" Revision 09 (May 1, 2010).

Lost Opportunity Cost Billing Error Resolution

On November 22, 2011, PJM filed a petition with FERC requesting a procedural framework within which to correct settlements of balancing operating reserve lost opportunity cost billings between 2009 and 2011.[40] The tariff provides for the calculation of lost opportunity cost as real-time LMP less the higher of the price or cost offer.[41] However, the software code included in the Market Settlement Calculation System (MSCS) calculated lost opportunity cost as real-time LMP less the price offer.[42] As a result, certain participants who regularly included cost offers higher than price offers and received operating reserve credits, received significant overpayments during the relevant period. PJM identified the need to correct its billings as provided in the tariff for an initial amount of approximately $96.6 million.[43]

PJM and the MMU engaged in discussions with Dominion Resources Services, Inc. (Dominion) and Ingenco Wholesale Power, L.L.C. (Ingenco), the participants who received most of the overpayments, to calculate a billing adjustment that represented both companies' generating units' real costs.[44] Both participants submitted data regarding their fuel supply arrangements, fuel costs, operating characteristics of the relevant units and other factors that impact their final production cost. On August 16, 2012, PJM submitted an Offer of Settlement and Stipulation (Stipulation) specifying the terms and conditions agreed to by all parties and the final refunds from Dominion and Ingenco.[45]

Black Start and Voltage Support Units

Certain units located in the Western Region are relied on for their black start capability and for voltage support 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 MMU recommended that PJM dispatchers explicitly log the reasons that these units are run out-of-merit whether to comply with black start requirements or to provide voltage support in order to correctly assign the associated charges.

On August 8, 2012, the PJM Market Implementation Committee (MIC) endorsed a charge presented by the MMU to prepare a proposal to correct the allocation of make whole payments (in the form of operating reserve charges) attributable to the operation of units for black start requirement and black start testing.[46]

PJM filed proposed revisions to PJM's tariff and operating agreement with FERC to change the short term allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for reliability purposes. The proposal also included a solution to correct the allocation of the cost of all operating reserves paid to units providing black start or performing black start testing.[47] The proposed revision allocated the costs of day-ahead operating reserves and balancing operating reserve of such units scheduled in the Day-Ahead Energy Market and/or committed in real time according to Schedule 6A of the OATT. This solution was consistent with the MMU's recommendation. FERC accepted the proposed revisions with December 1, 2012 as the effective date.

Con Edison – PSEG Wheeling Contracts Support

It appears that 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.[48] These units are often run out-of-merit and received 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.

40 See Petition of PJM Interconnection, L.L.C. for Institution of Proceeding to Determine Proper Billing Adjustments and for Waiver of Tariff, Docket No. ER12-469-000 (December 22, 2011) (December 22nd Petition).
41 OATT Attachment K - Appendix § 3.2.3 (f) & (f-1).
42 December 22nd Petition at 2–3.
43 *Id.* at 4; OA Schedule 1 § 15.6.
44 *Id.* at 8–9.
45 See Offer of Settlement and Stipulation of PJM Interconnection, L.L.C., Docket No. ER12-469 (August 16, 2012).
46 See "Minutes," from PJM's MIC August 8, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120808/20120808-minutes.ashx> (Accessed January 11, 2013).
47 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).
48 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.

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[49] Under the rules providing for credits for reactive service, 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 2012, units providing reactive services were paid $21.9 million in balancing operating reserve credits in order to cover their total energy offer. Of these credits, 92.1 percent were paid by deviations in the RTO Region, 6.4 percent by real-time load and real-time exports in the RTO Region, 1.2 percent by deviations in the Eastern and Western Regions and the remaining 0.3 percent by real-time load and real-time exports in the Western Region.

Table 3-41 shows the impact of these credits in each of the balancing operating reserve categories.

Table 3-41 Impact of credits paid to units providing reactive services on the balancing operating reserve rates ($/MWh): 2012

		Balancing Operating Reserve Rates ($/MWh)		Difference	
Category	Region	Current	Without Credits to Units Providing Reactive Services	($/MWh)	Percentage
Reliability	RTO	0.024	0.023	(0.002)	(7.2%)
	East	0.022	0.022	0.000	0.0%
	West	0.115	0.115	(0.000)	(0.1%)
Deviation	RTO	0.815	0.675	(0.139)	(17.1%)
	East	0.333	0.332	(0.001)	(0.4%)
	West	0.126	0.124	(0.003)	(2.1%)

49 OATT Attachment K - Appendix § 3.2.3B (f).

On October 10, 2012 and November 7, 2012 the MMU presented this issue at PJM's Market Implementation Committee (MIC).[50,51] The MIC endorsed the issue charge and approved merging this issue with the long term solution of the allocation of the cost of day-ahead operating reserves for reliability.[52]

The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be equal to the positive difference between total offer (including no load and startup costs) and energy revenues. In addition, the MMU recommends that reactive services credits be calculated on segments which include all hours for which unit provides reactive service. Segments should be the higher of hours needed for reactive support and minimum run time.

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 2012, 54.5 percent of all up-to congestion transactions were profitable.[53]

The MMU calculated the up-to congestion transactions that would have remained if operating reserve charges had been applied. It was assumed that up-to congestion transactions would have had the same shares of profitable and unprofitable transactions after paying operating reserve charges as occurred when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, only 34.3 percent of all up-to congestion transactions would have been made. Even with this reduction in the

50 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>. (Accessed January 11, 2013)

51 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> (Accessed January 11, 2013).

52 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).

53 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.

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.

Table 3-42 shows the impact that including the identified 34.3 percent of up-to congestion transactions in the allocation of operating reserve charges would have had on the operating reserve charge rates in 2012. For example, the RTO deviations rate would have been reduced by 59.3 percent.

Table 3-42 Up-to congestion transactions impact on operating reserve rates: 2012

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.200	0.177	(0.023)	(11.3%)
RTO Deviations	0.815	0.332	(0.483)	(59.3%)
East Deviations	0.333	0.191	(0.142)	(42.7%)
West Deviations	0.126	0.038	(0.088)	(69.9%)
Lost Opportunity Cost	1.322	0.538	(0.784)	(59.3%)
Canceled Resources	0.024	0.010	(0.014)	(59.3%)

The MMU recommends, while the up-to congestion transaction product remains and without a plan to examine the allocation of all operating reserve charges, PJM should require all up-to congestion transactions to pay day-ahead and balancing operating reserve charges.

Capacity Market

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

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

Table 4-1 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction (BRA), for every planning year for which a BRA has been run to date. For almost all auctions held from 2007 to the present, the PJM region failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.[2]
- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the PMSS, which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which a BRA has been run to date. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.

Overview

RPM Capacity Market

Market Design

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

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

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

4 The terms *PJM Region, RTO Region and RTO* are synonymous in the *2011 State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.

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

100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[6] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13 and four months, prior to the delivery year. Also effective for the 2012/2013 Delivery Year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[7]

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

Market Structure

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

6 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.
9 There are 26 locational deliverability areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).

all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[10,11,12]

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

Market Conduct

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

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

11 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

12 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

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

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

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

16 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, see "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

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

- **2013/2014 RPM Second Incremental Auction.** Of the 163 generation resources which submitted offers, unit-specific offer caps were calculated for eight generation resources (4.9 percent). The MMU calculated offer caps for 77 generation resources (47.2 percent), of which 65 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Base Residual Auction.**[17] Of the 1,152 generation resources which submitted offers, unit-specific offer caps were calculated for 141 resources (12.2 percent). The MMU calculated offer caps for 698 resources (60.6 percent), of which 550 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM First Incremental Auction.** Of the 190 generation resources which submitted offers, unit-specific offer caps were calculated for 21 generation resources (11.1 percent). The MMU calculated offer caps for 96 generation resources (50.5 percent), of which 71 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 188 generation resources (16.1 percent). The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values.

Market Performance

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

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.9 percent in 2011 to 7.5 percent in 2012.[18]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor increased from 83.7 percent in 2011 to 84.1 percent in 2012.
- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (NERC) criteria, an outage may be classified as an OMC outage if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. In 2012, 12.4 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Conclusion

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

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

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

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

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

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in 2012. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in 2012.

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

Table 4-2 RPM Related MMU Reports

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

Installed Capacity

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

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

RPM Capacity Market

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

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

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

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

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

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

21 Wind resources accounted for 779.6 MW of installed capacity in PJM on December 31, 2012. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data. There are additional wind resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market.

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

Market Structure

Supply

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

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

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

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

As shown in Table 4-4 and Table 4-15, in the 2014/2015 auction, the 43 additional generation resources offered consisted of 39 new resources (1,038.5 MW), two additional resources imported (577.6 MW), one reactivated resource (8.1 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource (22.5 MW). The new Generation Capacity Resources consisted of 17 solar resources (30.2 MW), seven wind resources (146.6 MW), seven diesel resources (31.5 MW), five hydroelectric resources (132.7), two CT units (76.7 MW), and one combined cycle unit (620.8 MW). The reactivated Generation Capacity Resources consisted of one diesel resource (8.1 MW). The 61 fewer generation resources offered consisted of 12 deactivated resources (936.8 MW), 12 additional resources excused from offering (1,129.9 MW), 32 additional resources committed fully to FRR (2,175.0 MW), four Planned Generation Capacity Resources not offered (240.0 MW), and one external generation resource not offered (6.6 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2013/2014 BRA: two combustion turbine (CT) units (2.5 MW).

As shown in Table 4-4 and Table 4-16, in the 2015/2016 auction, the 111 additional generation resources offered consisted of 49 new resources (6,221.0 MW), 45 resources that were previously entirely FRR committed (4,803.0 MW), 13 additional resources imported (1,072.2 MW), three resources that were excused and not offered in the 2014/2015 BRA (30.8 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource not offered in the 2014/2015 BRA (42.7 MW). The new Generation Capacity Resources consisted of 15 solar resources (13.8 MW), eight CT resources (1,348.4 MW), seven combined cycle resources (4,526.9 MW), six wind resources (104.9 MW), five diesel resources (13.6 MW), five hydroelectric resources (143.6 MW), two fuel cell resources (28.5 MW), and one steam unit (41.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2015/2016 Delivery Year: two CT resources (283.6 MW). The 95 fewer generation resources offered consisted of 49 additional resources excused from offering (3,761.1 MW), 29 deactivated resources (3,713.2 MW), eight additional resources committed fully to FRR (471.8 MW), three less resources resulting from aggregation of RPM resources, three external resources not offered (866.4 MW), one resource that is no longer a PJM capacity resource (1.2 MW), one Planned Generation Capacity Resource not offered (1.5 MW), and one resource unoffered and unexcused (4.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2014/2015 BRA: six steam units (918.5 MW).

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

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

	UCAP (MW)								
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
Total internal capacity @ 01-Jun-11	159,882.7	66,329.7	32,733.0	11,684.2	1,460.3	7,425.8	4,167.5		
Reclassification of Duquesne resources to internal	3,187.2	0.0	0.0	0.0	0.0	0.0	0.0		
New generation	785.5	173.1	59.7	0.0	0.0	0.0	0.0		
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Generation cap mods	(1,637.3)	(1,012.5)	(444.9)	(540.0)	(31.8)	(379.2)	(509.0)		
DR mods	8,028.7	3,829.7	1,480.9	1,076.9	64.6	423.3	67.6		
EE mods	652.5	186.9	24.4	162.3	0.0	4.1	0.9		
EFORd effect	(944.1)	(502.1)	(185.1)	47.3	5.8	(42.6)	18.3		
DR and EE effect	(1.9)	(0.9)	(0.5)	(0.4)	0.0	0.0	0.0		
Total internal capacity @ 01-Jun-12	169,953.3	69,003.9	33,667.5	12,430.3	1,498.9	7,431.4	3,745.3	5,416.0	
Correction in resource modeling	0.0	13.0	0.0	0.0	81.3	0.0	28.5	0.0	
Adjusted internal capacity @ 01-Jun-12	169,953.3	69,016.9	33,667.5	12,430.3	1,580.2	7,431.4	3,773.8	5,416.0	
Integration of existing ATSI resources	13,175.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
New generation	1,104.4	172.5	110.3	1.8	0.0	108.8	101.9	1.8	
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Generation cap mods	(969.4)	(1,007.7)	(884.9)	(113.8)	12.4	(180.2)	(180.2)	(11.0)	
DR mods	1,894.1	900.2	689.5	(207.4)	9.7	646.1	431.2	61.8	
EE mods	100.8	(34.9)	(0.3)	(51.9)	(8.1)	3.3	(0.3)	(20.7)	
EFORd effect	(589.3)	27.7	117.5	(292.5)	18.1	26.0	48.3	(159.4)	
DR and EE effect	9.1	4.2	1.0	1.8	0.1	0.2	0.1	0.4	
Total internal capacity @ 01-Jun-13	184,678.2	69,078.9	33,700.6	11,768.3	1,612.4	8,035.6	4,174.8	5,288.9	
Correction in resource modeling	(31.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Adjusted internal capacity @ 01-Jun-13	184,647.0	69,078.9	33,700.6	11,768.3	1,612.4	8,035.6	4,174.8	5,288.9	
Integration of existing DEOK resources	4,816.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
New generation	1,038.5	875.8	697.2	2.7	48.0	6.8	1.5	0.0	
Reactivated generation	8.1	8.1	8.1	0.0	0.0	8.1	0.0	0.0	
Generation cap mods	(991.9)	(175.2)	(102.3)	(242.8)	(161.9)	9.3	(0.5)	(2.8)	
DR mods	6,940.0	6,653.8	2,438.6	2,727.5	241.9	547.0	205.0	681.7	
EE mods	49.4	55.6	1.2	52.0	3.0	(0.6)	(0.6)	7.5	
EFORd effect	(271.7)	(248.0)	(93.5)	54.1	(17.8)	104.8	25.5	106.4	
DR and EE effect	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total internal capacity @ 01-Jun-14	196,235.8	76,249.0	36,649.9	14,361.8	1,725.6	8,711.0	4,405.7	6,081.7	10,545.2
New generation	6,786.1	3,486.9	2,523.3	661.0	297.7	801.0	793.9	661.0	843.8
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Generation cap mods	(5,118.9)	(361.0)	7.0	(372.3)	(2.0)	(138.9)	5.5	(372.3)	74.4
DR mods	5,441.4	(149.6)	606.9	(1,583.0)	(123.8)	(33.9)	(70.7)	(34.8)	2,729.0
EE mods	220.1	29.4	25.4	(3.0)	(5.0)	5.1	3.5	12.9	78.2
EFORd effect	938.4	508.9	229.8	156.4	7.0	170.3	87.9	114.4	133.6
DR and EE effect	54.4	29.5	12.8	6.2	0.9	4.0	2.0	3.4	3.3
Total internal capacity @ 01-Jun-15	204,557.3	79,793.1	40,055.1	13,227.1	1,900.4	9,518.6	5,227.8	6,466.3	14,407.5

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

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

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

Demand

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

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

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

On June 1, 2012, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.9 percent (Table 4-6), up slightly from 71.4 percent on June 1, 2011. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 28.1 percent, down slightly from 28.6 percent on June 1, 2011. Prior to the 2012/2013 Delivery Year, obligation is defined as cleared and make-whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM Auctions for the delivery year.

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

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	52,835.1	40,829.7	15,141.3	4,901.4	13,141.3	6,038.7	18,526.8	151,414.3
Percent of total obligation	34.9%	27.0%	10.0%	3.2%	8.7%	4.0%	12.2%	100.0%

Market Concentration

Preliminary Market Structure Screen

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

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

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

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

Auction Market Structure

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

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

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

Second Incremental Auction, and the 2015/2016 BRA.[26] The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[27,28,29] In the 2012/2013 BRA, all participants included in the incremental supply of EMAAC passed the test. In the 2014/2015 BRA, all participants included in the incremental supply in MAAC passed the test. In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price.[30] The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 4-8 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI3). The RSIx is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSIx is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSIx is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

26 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

27 See OATT Attachment DD § 6.5.

28 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

29 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

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

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

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

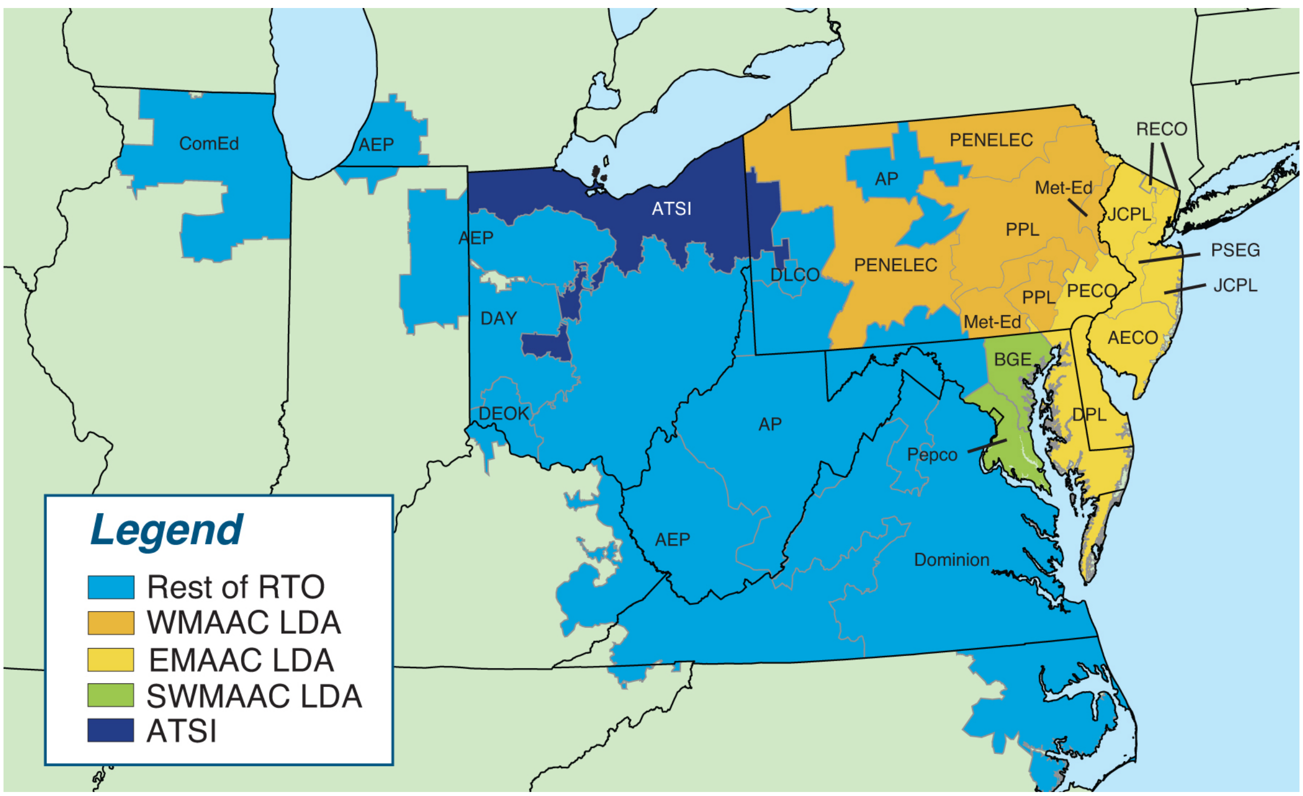
31 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[32] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[33] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

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

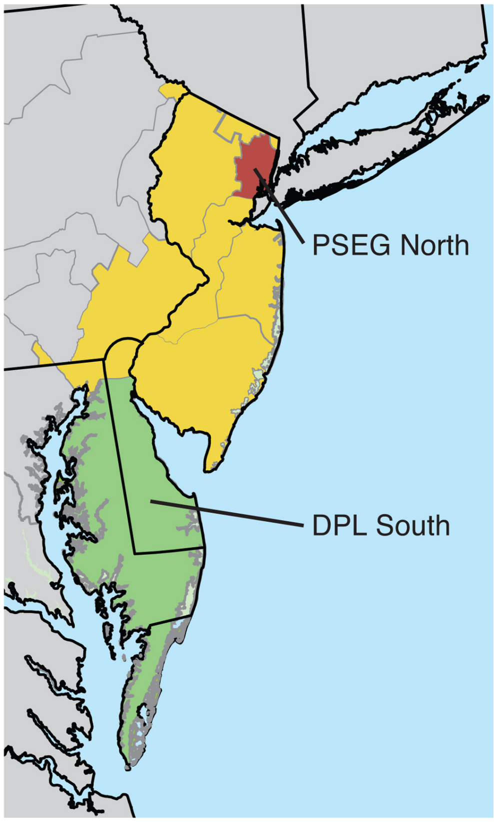
Figure 4-1 PJM Locational Deliverability Areas



32 Prior to the 2012/2013 delivery year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.

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

Figure 4-2 PJM RPM EMAAC subzonal LDAs



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity outside PJM.[34]

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

Importing Capacity

Existing External Generation Capacity Resource

Generation external to the PJM region is eligible to be offered into an RPM Auction if it meets specific requirements.[35, 36] Firm transmission service from the unit to the border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point-to-point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Market.[37]

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

34 OATT Attachment DD § 5.6.6(b).

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

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

37 OATT, Schedule 1, Section 1.10.1A.

transactions must designate the transaction as such when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits. If the offer is not accepted in the Day-Ahead Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

Planned External Generation Capacity Resource

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[38, 39] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[40] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction.[41]

Exporting Capacity

Non-firm transmission can be used to export capacity from the PJM region. A Generation Capacity Resource located in the PJM region not committed to service of PJM loads may be removed from PJM Capacity Resource status if the Capacity Market Seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[42] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[43]

The MMU evaluates requests submitted by Capacity Market Sellers to export Generation Capacity Resources, makes a determination as to whether the resource meets the applicable criteria to export, and must inform both the Capacity Market Seller and PJM of such determination.[44]

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

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

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

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

40 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).

41 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

42 OATT Attachment DD § 6.6(g).

43 *Id.*

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

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

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

Demand-Side Resources

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

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Interruptible Load for Reliability (ILR).** Interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the second incremental auction. The ILR product was eliminated after the 2011/2012 Delivery Year.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[47] The Energy Efficiency (EE) resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[48]

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

- **Annual DR.** Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for at least a 10-hour duration during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April.
- **Extended Summer DR.** Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to

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

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

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

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

49 134 FERC ¶ 61,066 (2011).

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

be capable of maintaining each interruption for at least a 10-hour duration during the hours of 10:00 a.m. to 10:00 p.m. EPT.

- **Limited DR.** Demand Resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for at least a 6-hour duration during the hours of 12:00 p.m. to 8:00 p.m. EPT.

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

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

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

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

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

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

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,037.5	10,458.8	839.1	870.9	0.0	0.0
2014/2015	13,717.4	14,226.8	923.9	956.4	0.0	0.0
2015/2016	14,303.2	14,832.8	890.8	922.5	0.0	0.0

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

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	10,876.6	11,329.7	(535.6)	(558.1)	0.0	0.0	10,341.0	10,771.6
01-Jun-14	14,641.3	15,183.2	(5.7)	(5.9)	0.0	0.0	14,635.6	15,177.3
01-Jun-15	15,194.0	15,755.3	0.0	0.0	0.0	0.0	15,194.0	15,755.3

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

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

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

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

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

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to Capacity Resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[58,59,60]

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[61] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. Capacity resource owners could provide ACR data by providing their own unit-specific data or by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[62]

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

58 See OATT Attachment DD § 6.5.

59 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

60 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

61 OATT Attachment DD § 6.8 (b).

62 OATT Attachment DD § 6.8 (a).

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed. The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for combined cycle (CC) and combustion turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, increasing the percentage value used in the screen to 90 percent for CC and CT plants, eliminating the net-short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation. The 2015/2016 RPM Base Residual Auction was the second BRA conducted under the revised MOPR and the first conducted under the subsequent FERC Orders related to the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2014/2015 BRA							
Non-APIR units	ACR	$47.04	$34.61	$84.19	$222.70	$58.86	$110.52
	Net revenues	$112.21	$29.80	$14.52	$306.01	$226.46	$152.35
	Offer caps	$8.92	$16.34	$74.66	$28.52	$16.68	$25.32
APIR units	ACR	NA	$65.34	$278.46	$511.79	$330.13	$437.99
	Net revenues	NA	$18.24	$55.97	$222.06	$138.36	$182.98
	Offer caps	NA	$51.46	$222.49	$313.68	$191.78	$274.45
	APIR	NA	$38.99	$185.24	$313.37	$1.67	$268.95
	Maximum APIR effect						$744.80
2014/2015 First IA							
Non-APIR units	ACR	$37.22	$29.94	$77.94	$223.40	$41.44	$197.18
	Net revenues	$139.02	$12.59	$18.66	$156.75	$82.18	$136.68
	Offer caps	$1.13	$17.35	$59.28	$93.14	$33.01	$83.55
APIR units	ACR	NA	$440.52	$328.42	$329.08	NA	$331.18
	Net revenues	NA	$41.67	$8.28	$245.05	NA	$229.92
	Offer caps	NA	$398.85	$320.14	$110.70	NA	$126.15
	APIR	NA	$417.50	$70.39	$119.70	NA	$123.05
	Maximum APIR effect						$761.69

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

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2015/2016 BRA							
Non-APIR units	ACR	$50.33	$36.07	$85.46	$232.16	$81.94	$113.51
	Net revenues	$160.85	$34.32	$35.86	$248.90	$265.61	$148.07
	Offer caps	$5.89	$11.34	$49.70	$26.50	$7.73	$17.86
APIR units	ACR	$163.25	$334.57	$192.87	$471.60	$41.74	$401.95
	Net revenues	$8.33	$17.93	$17.39	$221.10	$57.91	$166.81
	Offer caps	$154.94	$316.69	$175.53	$264.18	$8.15	$246.63
	APIR	$116.55	$293.45	$87.42	$265.13	$23.35	$238.79
	Maximum APIR effect						$776.46

2012/2013 RPM Base Residual Auction

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

Of the 1,133 generation resources which submitted offers, 118 (10.4 percent) included an APIR component. As shown in Table 4-17, the weighted-average gross ACR for resources with APIR ($464.65 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($167.62 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $351.74 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($559.97 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($1,155.57 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2012/2013 ATSI Integration Auction

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

2012/2013 RPM First Incremental Auction

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

Of the 162 generation resources which submitted offers, 14 resources (8.6 percent) included an APIR component. As shown in Table 4-17, the weighted-average gross ACR for resources with APIR ($367.75 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($229.59 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $222.35 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($459.80 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($549.57 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2012/2013 RPM Second Incremental Auction

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

2012/2013 RPM Third Incremental Auction

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

2013/2014 RPM Base Residual Auction

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

Of the 1,170 generation resources which submitted offers, 92 (7.9 percent) included an APIR component. As shown in Table 4-18, the weighted-average gross ACR for resources with APIR ($390.05 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($134.44 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $268.59 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.37 per MW-day, which is the average APIR ($1.31 per MW-day) for the previously estimated default ACR values in the 2012/2013 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($352.55 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($1,304.36 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2013/2014 RPM First Incremental Auction

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

Of the 192 generation resources which submitted offers, 27 resources (14.1 percent) included an APIR component. As shown in Table 4-18, the weighted-average gross ACR for resources with APIR ($426.53 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($160.05 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $265.55 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.37 per MW-day. The highest APIR for a technology ($329.36 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($593.49 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2013/2014 RPM Second Incremental Auction

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

2014/2015 RPM Base Residual Auction

As shown in Table 4-15, 1,152 generation resources submitted offers in the 2014/2015 RPM Base Residual Auction. Unit-specific offer caps were calculated for 141 generation resources (12.2 percent of all generation resources offered) including 138 generation resources (12.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and three generation resources (0.3 percent) without an APIR component. The MMU calculated offer caps for 709 generation resources (61.5 percent), of which 561 (48.7 percent) were based on the technology specific default (proxy) ACR values. Of the 1,152 generation resources, 22 Planned Generation Capacity Resources had uncapped offers (1.9 percent), 11 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.0 percent), six generation resources had uncapped planned uprates along with price taker status for the existing portion (0.5 percent), while the remaining 415 generation resources were price takers (36.0 percent), of which the offers for 413 generation resources were zero and the offers for two generation resources were set to zero because no data were submitted. The MOPR was applied and the MOPR exception process was applied to two units.

Of the 1,152 generation resources which submitted offers, 138 (12.0 percent) included an APIR component. As shown in Table 4-19, the weighted-average gross ACR for resources with APIR ($437.99 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($274.45 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $268.95 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.42 per MW-day, which is the average APIR ($1.37 per MW-day) for the previously estimated default ACR values in the 2013/2014 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($313.37 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($744.80 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2014/2015 RPM First Incremental Auction

As shown in Table 4-19, 190 generation resources submitted offers in the 2014/2015 RPM First Incremental Auction. Unit-specific offer caps were calculated for 21 generation resources (11.1 percent of all generation resources offered), all of which included an APIR component. The MMU calculated offer caps for 96 generation resources (50.5 percent), of which 71 (37.4 percent) were based on the technology specific default (proxy) ACR values. Of the 190 generation resources, five Planned Generation Capacity Resources had uncapped offers (2.6 percent), 11 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (5.8 percent), four generation resources had uncapped planned uprates along with price taker status for the existing portion (2.1 percent), while the remaining 85 generation resources were price takers (44.7 percent), of which the offers for 85 generation resources were zero and the offers for no generation resources were set to zero because no data were submitted.

Of the 190 generation resources which submitted offers, 21 (11.1 percent) included an APIR component. As shown in Table 4-19, the weighted-average gross ACR for resources with APIR ($331.18 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($126.15 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $123.05 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.42 per MW-day. The highest APIR for a technology ($417.50 per MW-day) was for combustion turbine (CT) units. The maximum APIR effect ($761.69 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2015/2016 RPM Base Residual Auction

As shown in Table 4-20, 1,168 generation resources submitted offers in the 2015/2016 RPM Base Residual Auction. Unit-specific offer caps were calculated for 188 generation resources (16.1 percent) including 171 generation resources (14.6 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 17 generation resources (1.5 percent) without an APIR component. The MMU calculated offer caps for 670 generation resources, of which 478 were based on the technology specific default (proxy) ACR values. Of the 1,168 generation resources, 32 Planned Generation Capacity Resources had uncapped offers, 25 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion, seven generation resources had uncapped planned uprates along with price taker status for the existing portion, while the remaining 459 generation resources were price takers, of which the offers for 458 generation resources were zero and the offer for one generation resources was set to zero because no data were submitted.

Of the 1,168 generation resources which submitted offers, 171 (14.6 percent) included an APIR component. As shown in Table 4-20, the weighted-average gross ACR for resources with APIR ($401.95 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($246.63 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $238.79 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.48 per MW-day, which is the average APIR ($14.42 per MW-day) for the previously estimated default ACR values in the 2014/2015 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($293.45 per MW-day) was for combustion turbine (CT) units. The maximum APIR effect ($776.46 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Market Performance[66]

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

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

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

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

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

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

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

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

		RPM Clearing Price ($ per MW-day)								
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54	
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11	
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$237.33	
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37	
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14	$27.73
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$54.82	$20.00
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$40.00	$10.00	$40.00	$40.00	$10.00	$7.01
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00

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

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

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

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$100.22	152,226.6	365	$5,568,395,048
2014	$124.72	155,428.1	365	$7,075,365,425
2015	$148.33	160,866.8	365	$8,709,157,810
2016	$161.62	164,563.9	152	$4,042,675,320

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

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

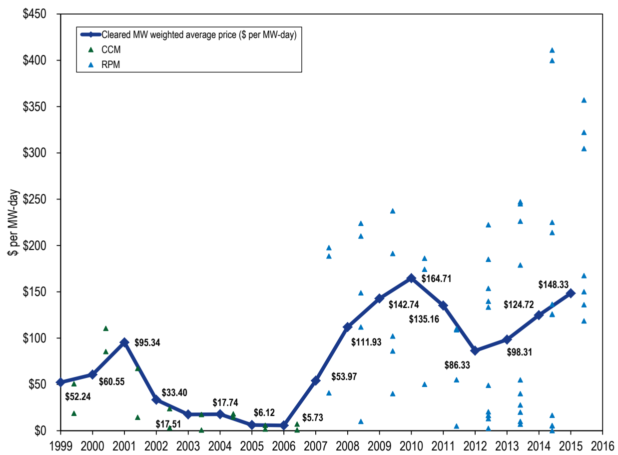


Table 4-24 shows the RPM annual charges to load. For the 2012/2013 planning year, RPM annual charges to load total approximately $3.9 billion.

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

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

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on

72 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2015 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices.

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

74 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

75 Prior to the 2009/2010 Delivery Year, the Final UCAP Obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the Final UCAP Obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 Delivery Year, the Final UCAP Obligation is determined after the clearing of the final Incremental Auction. Prior to the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after the final Incremental Auction. The 2013/2014, 2014/2015, and 2015/2016 Net Load Prices are not finalized. The 2013/2014, 2014/2015, and 2015/2016 Obligation MW are not finalized.

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

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity during that period. Nuclear units typically run at a greater than 90 percent capacity factor. In 2012, nuclear units had a capacity factor of 92.4 percent. Combined cycle units ran more often in 2012 than in the same period in 2011, increasing from a 46.0 percent capacity factor in 2011 to a 60.4 percent capacity factor in 2012. In contrast, the capacity factor for steam units decreased from 51.0 percent in 2011 to 45.5 percent in 2012.

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

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

Generator Performance Factors

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

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

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

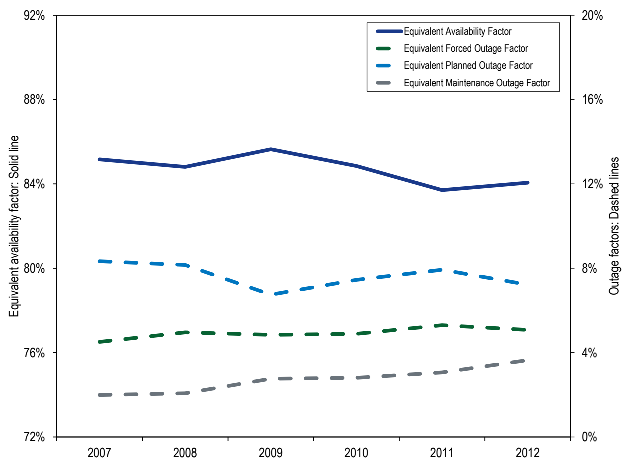


Table 4-26 EAF by unit type: 2007 through 2012

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

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

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

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

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

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

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

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

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

Generator Forced Outage Rates

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

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours,78 service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours. The EFORd metric includes all forced outages, regardless of the reason for those outages.

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

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

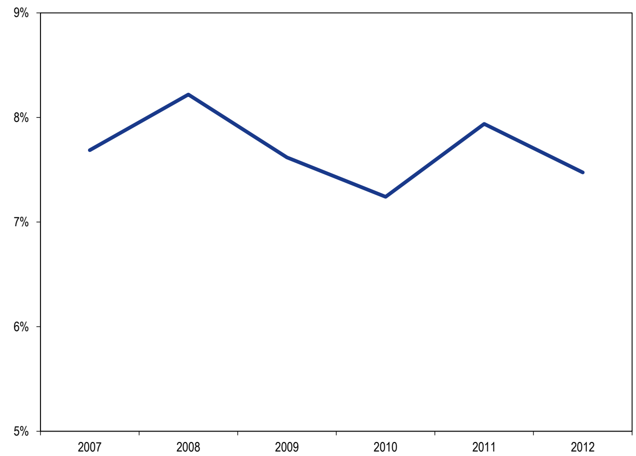


Table 4-30 shows the class average EFORd by unit type.

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

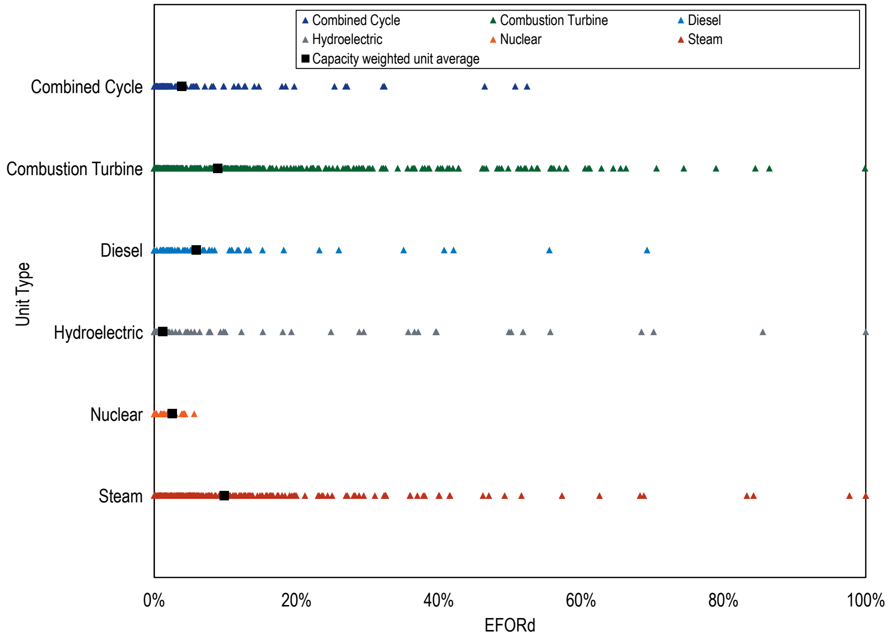
	2007	2008	2009	2010	2011	2012	NERC EFORd 2007 to 2011 Average
Combined Cycle	3.7%	3.4%	4.3%	3.8%	3.5%	4.2%	4.4%
Combustion Turbine	17.0%	14.2%	9.8%	8.9%	8.0%	8.2%	9.4%/9.7%
Diesel	11.7%	11.0%	9.9%	5.9%	9.6%	5.6%	12.5%
Hydroelectric	2.2%	2.1%	3.2%	1.2%	2.9%	4.4%	5.3%
Nuclear	1.2%	1.1%	4.1%	2.5%	2.8%	1.6%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

Distribution of EFORd

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

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

Figure 4-6 PJM 2012 distribution of EFORd data by unit type



Other Forced Outage Rate Metrics

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

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

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

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

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).79 An outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[80] Not all outages caused

79 Generator Availability Data System Data Reporting Instructions states, "The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control... There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. The standard sets a boundary on the generator side of the power station for the determination of equipment outside management control." The Generator Availability Data System Data Reporting Instructions can be found on the NERC website: <http://www.nerc.com/files/2009_GADS_DRI_Complete_SetVersion_010111.pdf>.

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

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

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

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

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

Table 4-31 OMC Outages: 2012

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

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

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

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

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

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

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

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

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

83 See New York Independent System Operator, "Manual 4: Installed Capacity Manual," Version 6.20. (January, 24 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_mnl.pdf> When a Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource is forced into an outage by an equipment failure that involves equipment located on the electric network beyond the step-up transformer, and including such step-up transformer, the NYISO shall not treat the outage as a forced outage for purposes of calculating the amount of Unforced Capacity such Installed Capacity Suppliers are qualified to supply in the NYCA. This exception is limited to an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer on the output side of the Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource. This exception does not apply to fuel related outages or derates or other cause codes that might be classified as Outside Management Control in the NERC Data reporting Instructions. NYISO only accepts OMC outages for outages at or beyond the step-up transformer.

The MMU recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage. The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market after appropriate notice.

All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that pending elimination of OMC outages, that PJM review all requests for OMC carefully, develop a clear, transparent set of written public rules governing the designation of outages as OMC and post those guidelines. Any resultant OMC outages may be considered by PJM but should not be reflected in forced outage metrics which affect system planning or market payments to generating units.

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

Table 4-32 PJM EFORd vs. XEFORd: 2012

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

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[84] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

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

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

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

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

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

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[86] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 4-34 Contributions to Economic Outages: 2012

	Contribution to Economic Reasons
Lack of fuel (OMC)	96.2%
Lack of water (Hydro)	2.3%
Lack of fuel (Non-OMC)	1.3%
Fuel conservation	0.2%
Other economic problems	0.0%
Ground water or other water supply problems	0.0%
Total	100.0%

EFORd, XEFORd and EFORp

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

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[87] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than EFORd, suggesting that units elect to take forced outages during off-peak hours, as much as it is

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

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

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

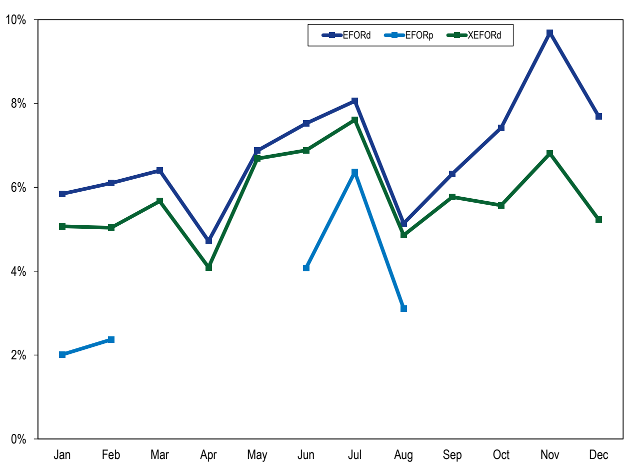
Table 4-35 PJM EFORd, XEFORd and EFORp data by unit type: 2012[88]

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

Performance By Month

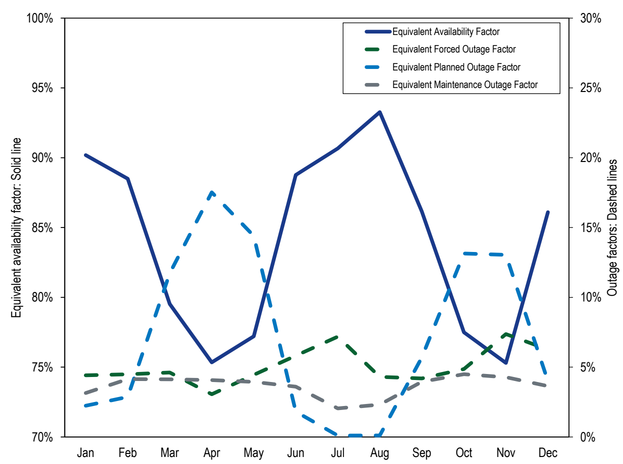
On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 4-7, demonstrating that units had fewer outages during peak hours than would have been expected based on EFORd.

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



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

Figure 4-8 PJM monthly generator performance factors: 2012



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

Demand-Side Response (DSR)

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.

Overview

- **Demand-Side Response Activity.** In 2012, the total MWh of load reduction under the Economic Load Response Program increased by 124,170 MWh compared to the same period in 2011, from 17,398 MWh in 2011 to 141,568 MWh in 2012, a 714 percent increase. Total payments under the Economic Program increased by $7,106,385, from $2,052,996 in 2011 to $9,159,381 in 2012, a 346 percent increase.

  Settled MWh and credits were greater in 2012 compared to 2011, and there were more settlements submitted compared to the same period in 2010. Participation levels increased following the implementation of Order 745, on April 1, 2012, allowing payment of full LMP for demand resources. On the peak load day for 2012 (July 17, 2012), there were 2,302.4 MW registered in the Economic Load Response Program, compared to 2,041.5 MW for 2011 (July 21,2011).

  Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to participants in PJM demand side programs. In 2012, Load Management (LM) Program revenue decreased $156.0 million, or 32.0 percent, from $487 million to $331 million. Through 2012 Synchronized Reserve credits for demand side resources decreased by $4.9 million compared to the same period in 2011, from $9.4 million to $4.5 million in 2012.

- **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. 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 overcompliance to be reported when there is no actual overcompliance. 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 two events in 2012 should have been 3,713.4, rather than the 3,922.5 reported. Overall, compliance decreases from the reported 103.0 percent to 97.6 percent. This does not include locations that did not report their load during the emergency event days.

Conclusions

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.

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market locational marginal price (LMP). End use customers pay load serving entities (LSEs) an annual amount designed to recover, among other things, the total cost of wholesale power for the year.[1] End use customers

1 In PJM, load pays the average zonal LMP, which is the weighted average of the actual nodal locational marginal price. While individual customers have the option to pay nodal LMP, very few customers do so.

paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However, a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy, or the market price of capacity, the locational price of capacity. Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP, either on an average zonal or on a nodal basis. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. This market failure does not imply that PJM markets have failed. This market failure means that customers do not pay the actual hourly locational cost of energy as a result of the disconnect between wholesale markets and retail pricing. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the actual hourly locational price of power used by customers is determined by the wholesale power market, regardless of the average price actually paid by customers. The transition to a more functional demand side in the wholesale power market requires that the default energy price for all customers be the day-ahead or real-time hourly locational marginal price (LMP) and the locational clearing price of capacity. While the initial default energy price could be the zonal average LMP, the transition to nodal LMP pricing should begin.

PJM's Economic Load Response Program (ELRP) is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale zonal price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.[2] In PJM's Economic Load Response Program, participants have the option to receive credits for load reductions based on a more locationally defined pricing point than the zonal LMP. PJM's PRD program does incorporate some aspects of nodal pricing, although the link between the nodal wholesale price and the retail price is extremely attenuated.

FERC Order 745 was implemented effective April 1, 2012. Order 745 requires RTOs and ISOs to pay full LMP to demand resources rather than LMP less the cost of generation and transmission paid by retail customers, if the demand resources are cost effective as determined by a "Net Benefits Test" (NBT).[3] This approach is based on the view that dispatching demand resources may result in a net increase in cost to non-demand response loads, and requires the NBT as mitigation. The payment of full LMP to demand resources, effective April 1, 2012, increased participation in the Economic Load Response Program. This change explicitly permitted subsidies to be paid to retail customers on fixed rates that incorporate a fixed price of wholesale power, and to customers paying LMP for wholesale power. While the subsidy has a rationale as an incentive for fixed rate retail customers, there is no reason to provide this subsidy to LMP customers who are already receiving the price signal from the wholesale power market.

PJM's Load Management (LM) Program in the RPM market attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. The PJM market design also creates the opportunity for demand resources

2 While the primary purpose of the ELRP is to replicate the hourly zonal price signal to customers on fixed retail rate contracts, customers with zonal or nodal hourly LMP contracts are currently eligible to participate in the DA scheduling and the PJM dispatch options of the Program.

3 The NBT uses a single monthly price for PJM and does not reflect hourly, locational price differences in the Real-Time and Day-Ahead markets.

to participate in ancillary services markets.[4] Within the LM Program, there are new shortage pricing rules that increase maximum bid offers for the 2012/2013 DY to $1,500/MWh.

PJM's demand side programs, by design, provide a work around for end use customers that are not directly exposed to the incremental, locational costs of energy and capacity. The demand side programs should be understood as one relatively small part of a transition to a fully functional demand side for PJM markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

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 should be further modified to more accurately reflect compliance. Increases in load during event hours should not be considered zero response, 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.

PJM Demand Side Programs

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 5-1 provides an overview of the key features of PJM load response programs.[6] Interruptible Load for Reliability (ILR) ended with the 2011/2012 planning year.

Participation in Demand Side Programs

On April 1, 2012, FERC Order 745 was implemented in the PJM Economic Program, mandating payment of full LMP for dispatched demand resources. In 2012, in the Economic Program, participation increased compared to 2011. There were more settlements submitted and active registrations in 2012 compared to 2011, and credits increased.

Table 5-1 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
Registered ILR only	DR cleared in RPM; Registered ILR	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. ILR program ended with 2012/2013 DY.	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.

4 See *2012 State of the Market Report for PJM*, Volume 2, "Section 9: Ancillary Service Markets."

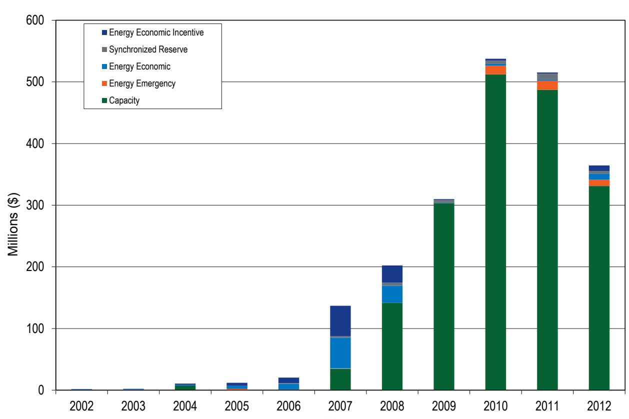
5 Prior to April 1, 2012, payment for the Economic Load Response Program was based on LMP minus the generation and transmission components of the retail rate.

6 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>.

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through 2012. 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 91.6 percent of all revenue received through demand response programs in 2012. In 2012, total payments under the Economic Program increased by $7,106,385, from $2,052,996 in 2011 to $9,159,381 in 2012, a 346 percent increase, but still only 2.6 percent of all revenue received through PJM demand response programs. In 2012, capacity revenue represents 93.2 percent of all revenue received by demand response providers, emergency energy revenue represented 2.9 percent, revenue from the economic program represented 2.6 percent and revenue from Synchronized Reserve represented 1.3 percent.

Capacity revenue decreased by $156.0 million, or 32.0 percent, from $487 million to $331 million in 2012, primarily due to lower clearing prices in the RPM market. Synchronized Reserve credits for demand side resources decreased by $4.9 million, from $9.4 million to $4.5 million in 2012, due to lower clearing prices in the Synchronized Reserve market. In 2012, there were two Load Management Event Days, occurring on July 17, and July 18, 2012.

Figure 5-1 Demand Response revenue by market: 2002 through 2012



Economic Program

Table 5-2 shows the number of registered sites and MW per peak load day for 2002 through 2012.[7] On July 17, 2012, there were 2,302.4 MW registered in the Economic Program compared to the 2,041.8 MW on July 21, 2011, a 12.8 percent increase in peak load day capability. This was still below peak load capability in 2009, when peak load capability was 2,486.6 MW. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. The implementation of LMP payments for Economic demand resources increased the amount of MWh reductions by 714 percent for 2012.

Table 5-3 shows registered sites and MW for the last day of each month for the period 2008 through 2012.[8] The average registered MW decreased by 151 MW from 2,344 in 2011 to 2,193 registered MW in 2012. The overall credits paid by the Economic Program increased to $9,159,381 in 2012 from $2,052,996 in 2011. Historically, registered MW have declined in June but 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. Thus, registrations represent the maximum level of potential participation. During 2012, the implementation of Order 745 caused all participants to have to register again during April 2012, causing a drop in registration levels during that month.

Table 5-2 Economic Program registration on peak load days: 2002 to 2012

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
3-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
2-Aug-06	253	1,100.7
8-Aug-07	2,897	2,498.0
9-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
6-Jul-10	899	1,725.7
21-Jul-11	1,237	2,041.8
17-Jul-12	885	2,302.4

7 Table 5-2 and Table 5-3 reflect distinct registration counts. They do not reflect the number of distinct sites registered for the Economic Program, as multiple sites may be aggregated within a single registration.

8 The site count and registered MW associated with May 2007 are for May 9, 2007. Several new sites registered in May of 2007 overstated their MW capability, and it remains overstated in PJM data.

Table 5-3 Economic Program registrations on the last day of the month: 2009 through 2012

	2009		2010		2011		2012	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	4,862	3,303	1,841	2,623	1,609	2,432	1,993	2,385
Feb	4,869	3,219	1,842	2,624	1,612	2,435	1,995	2,384
Mar	4,867	3,227	1,845	2,623	1,612	2,519	1,996	2,356
Apr	2,582	3,242	1,849	2,587	1,611	2,534	189	1,313
May	1,250	2,860	1,875	2,819	1,687	3,166	371	1,660
Jun	1,265	2,461	813	1,608	1,143	1,912	803	2,337
Jul	1,265	2,445	1,192	2,159	1,228	2,062	942	2,313
Aug	1,653	2,650	1,616	2,398	1,987	2,194	1,013	2,364
Sep	1,879	2,727	1,609	2,447	1,962	2,183	1,052	2,411
Oct	1,875	2,730	1,606	2,444	1,954	2,179	828	2,259
Nov	1,874	2,730	1,605	2,444	1,988	2,255	824	2,257
Dec	1,853	2,627	1,598	2,439	1,992	2,259	846	2,273
Avg.	2,508	2,852	1,608	2,435	1,699	2,344	1,071	2,193

Table 5-4 shows the zonal distribution of capability in the Economic Program on July 17, 2012. The PPL Control Zone included 227 sites and 355.3 MW, 25 percent of sites and 15 percent of registered MW in the Economic Program. The BGE Control Zone included 59 registrations and 626.6 MW, 7.6 percent of sites and 27 percent of registered MW in the Economic Program.

Table 5-4 Distinct registrations and sites in the Economic Program: July 17, 2012[9]

	Registrations	Sites	MW
AECO	8	8	34.9
AEP	15	15	100.7
AP	68	84	122.3
ATSI	23	23	78.3
BGE	59	83	626.6
ComEd	35	38	69.7
DAY	0	0	0.0
DEOK	1	1	35.0
DLCO	32	37	61.0
Dominion	36	50	236.2
DPL	16	16	85.2
JCPL	11	14	47.7
Met-Ed	80	91	71.2
PECO	164	218	128.2
PENELEC	77	81	55.1
Pepco	11	29	128.3
PPL	227	273	355.3
PSEG	22	38	66.6
RECO	0	0	0.0
Total	885	1,099	2,302.4

Total payments in Table 5-5 exclude incentive payments in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[10] Total MWh per peak-day, registered MW increased from 8.5 MWh in 2011 to 61.5 MWh in 2012, a 622 percent increase.

Table 5-5 Performance of PJM Economic Program participants excluding incentive payments: 2002 through 2012

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$10,213,828	$40	234.8
2007	714,148	$31,600,046	$44	285.9
2008	452,222	$27,087,495	$60	197.1
2009	57,157	$1,389,136	$24	23.0
2010	74,070	$3,088,049	$42	42.9
2011	17,398	$2,052,996	$118	8.5
2012	141,568	$9,159,381	$65	61.5

Figure 5-2 shows monthly economic program payments, excluding incentive payments, for 2007 through 2012. Economic Program credits declined from June 2008 through 2009. In 2009, payments were down significantly in every month compared to the same time period in 2007 and 2008. Lower energy prices and growth in the capacity market program were the biggest factors. Energy prices declined significantly in 2008 and again in 2009, and have remained low through

9 The second column of Table 5-4 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

10 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.

2012.[11] In 2012, credits were up substantially compared to 2011, following the implementation of Order 745 on April 1, 2012. Total payments were lower than 2007 and 2008, when prices in PJM were higher. Participation has increased since the implementation of Order 745 despite lower prices in 2012 than 2011, both in MWh and number of registrations.

Figure 5-2 Economic Program payments by month: 2007[12] through 2012

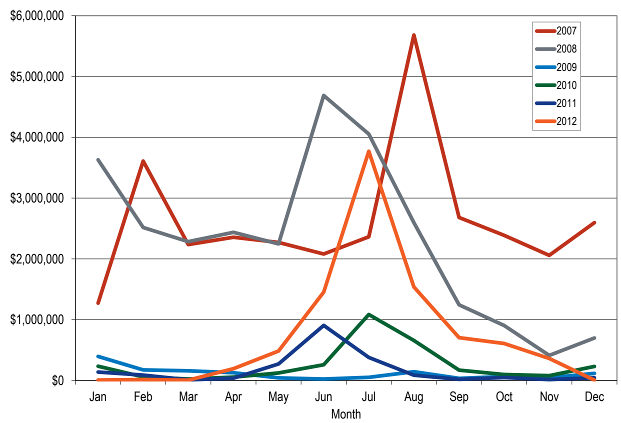


Table 5-6 shows 2012 performance in the Economic Program by control zone and participation type. The total number of curtailed MWh for the Economic Program was 141,567.7 and the total payment amount was $9,159,381.[13] The Dominion Control Zone accounted for $4,092,014 or 45 percent of all Economic Program credits, associated with 62,200.5 or 44 percent of total program MWh reductions. Table 5-6 shows the average participation in the Economic Program by zone and amount of customers in each zone. The Dominion zone does not include the most customers, but has the highest average MW reductions per customer and average credits per customer. Since the implementation of Order 745 on April 1, 2012, credits to demand resources through the Economic Program were $7,106,385 more than in 2011, an increase of 346 percent.

Table 5-7 shows the average participation in the PJM economic program by zone during 2012. Dominion and PSEG showed the largest MWh reduction per customer as well as credits per customer. PPL has the largest number of customers participating in the economic program during 2012, with 149.

Table 5-6 PJM Economic Program participation by zone: 2011 and 2012

	Credits			MWh Reductions		
	2011	2012	Percentage Change	2011	2012	Percentage Change
AECO	$0	$20,555	NA	0	98	NA
AEP	$24,279	$13,272	(45%)	310	155	(50%)
AP	$18,164	$1,065,216	5,764%	372	16,737	4,397%
ATSI	$1,829	$9,034	394%	19	110	467%
BGE	$730,278	$180,995	(75%)	2,295	1,004	(56%)
ComEd	$2,420	$460,123	18,915%	197	8,136	4,021%
DAY	$13,435	$0	(100%)	19	0	(100%)
DEOK	$0	$0	NA	0	0	NA
DLCO	$534	$3,032	468%	13	38	198%
Dominion	$1,107,895	$4,092,014	269%	11,938	62,201	421%
DPL	$59	$37,865	63,936%	0	287	81,760%
JCPL	$1,075	$244,640	22,650%	3	2,062	63,342%
Met-Ed	$17,429	$204,860	1,075%	184	3,618	1,868%
PECO	$78,559	$620,132	689%	1,707	8,686	409%
PENELEC	$3,376	$489,265	14,393%	81	9,461	11,611%
Pepco	$2,637	$118,789	4,404%	38	1,051	2,668%
PPL	$46,041	$442,950	862%	188	5,075	2,598%
PSEG	$4,986	$1,156,640	23,098%	34	22,850	67,365%
RECO	$0	$0	NA	0	0	NA
Total	$2,052,996	$9,159,381	346%	17,398	141,568	714%

11 The reduction was also the result in part of the revisions to the Customer Baseline Load (CBL) calculation effective June 12, 2008, and the newly implemented activity review process effective November 3, 2008.

12 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 retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 5-2 do not include these incentive payments.

13 If two different retail customers curtail the same hour in the same zone, it is counted as two curtailed hours.

Table 5-7 PJM Economic Program average participation by zone: 2012

Zone	Customers	Credits per Customer	MWh Reduction per Customer	MW Registered per Customer
AECO/JCPL	5	$53,039	432.0	16.5
AEP	4	$3,318	38.7	25.2
AP	33	$32,279	507.2	3.7
ATSI	5	$1,807	22.0	15.7
BGE	40	$4,525	25.1	15.7
ComEd	15	$30,675	542.4	4.6
DAY	0	$0	0.0	0.0
DEOK	0	$0	0.0	0.0
DLCO	21	$144	1.8	2.9
Dominion	19	$215,369	3,273.7	12.4
DPL	4	$9,466	71.6	21.3
Met-Ed	21	$9,755	172.3	3.4
PECO	118	$5,255	73.6	1.1
PENELEC	19	$25,751	497.9	2.9
Pepco	5	$23,758	210.1	25.7
PPL	149	$2,973	34.1	2.4
PSEG	7	$165,234	3,264.4	9.5
RECO	0	$0	0.0	0.0
Average	24	$19,698	304.4	5.0

Table 5-8 shows total settlements submitted by month for 2007 through 2012. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the expiration of the incentive program. In October of 2008, settlement submissions dropped significantly from the prior month and from the same month in 2007, a trend that continued through early 2009. This drop in participation corresponds with the implementation of the PJM daily review process, as well as the lower overall price levels in PJM. April of 2009 showed the lowest level of settlements submitted in the three year period, after which, settlements began to show steady growth. Settlements dropped off significantly after the summer period in 2009, and January through May of 2010 were generally lower than historical levels while summer of 2010 showed a moderate increase, consistent with 2009. February of 2012 showed the lowest level of settlements in the five year period, and 2011 and the first three months of 2012 overall showed a substantial decrease in the number of settlements submitted compared to previous years. Since the implementation of Order 745 in April 2012, settlements have increased, and settlements in July 2012 were consistent with summer settlements prior to 2011, though settlements decreased after the summer period ended.

Table 5-8 Settlement days submitted by month in the Economic Program: 2007 through 2012

Month	2007	2008	2009	2010	2011	2012
Jan	937	2,916	1,264	1,415	562	62
Feb	1,170	2,811	654	546	148	30
Mar	1,255	2,818	574	411	82	46
Apr	1,540	3,406	337	338	102	93
May	1,649	3,336	918	673	298	144
Jun	1,856	3,184	2,727	1,221	743	1,477
Jul	2,534	3,339	2,879	3,010	1,412	2,899
Aug	3,962	3,848	3,760	2,158	793	1,681
Sep	3,388	3,264	2,570	660	294	555
Oct	3,508	1,977	2,361	699	66	481
Nov	2,842	1,105	2,321	672	51	280
Dec	2,675	986	1,240	894	40	124
Total	27,316	32,990	21,605	12,697	4,591	7,872

Table 5-9 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2008 through 2012.[14] The number of active customers per month decreased in early 2009. Since then, monthly

Table 5-9 Distinct customers and CSPs submitting settlements in the Economic Program by month: 2008 through 2012

	2008		2009		2010		2011		2012	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	13	261	17	257	11	153	5	40	5	15
Feb	13	243	12	129	9	92	6	29	3	9
Mar	11	216	11	149	7	124	3	15	3	12
Apr	12	208	9	76	5	77	3	15	3	8
May	12	233	9	201	6	140	6	144	5	20
Jun	17	317	20	231	11	152	10	304	16	338
Jul	16	295	21	183	18	267	15	214	21	383
Aug	17	306	15	400	14	317	14	186	17	361
Sep	17	312	11	181	11	96	7	47	11	127
Oct	13	226	11	93	8	37	3	9	9	50
Nov	14	208	9	143	7	38	3	13	5	63
Dec	13	193	10	160	7	44	5	12	3	10
Total Distinct Active	24	522	25	747	24	438	20	610	24	520

14 November and December 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.

customer counts vary substantially. There was less activity in the first three months of 2012 than in any year since 2009. However, following the April 1 implementation of FERC Order 745 rules on demand resource compensation, activity returned to historical summer levels during the 2012 summer months.

Table 5-10 shows a frequency distribution of MWh reductions and credits at each hour for 2012. The period from hour ending 1500 EPT to 1800 EPT accounts for 51 percent of MWh reductions and 60 percent of credits.

Table 5-11 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in various price ranges. MWh reductions in the $0 to $25 bracket increased 8,872 percent from 18 MWh in 2011 to 1,615 MWh in 2012. MWh reductions in the $25 to $50 LMP bracket increased 3,725 percent from 2,028 MWh to 77,574 MWh in 2012.

Total Economic Program reductions increased by 124,786 MWh, from 16,782 MWh in 2011 to 141,568 MWh in 2012. Reductions occurred at all price levels. Approximately 76.9 percent of MWh reductions and 52.3 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75.

Table 5-10 Hourly frequency distribution of Economic Program MWh reductions and credits: 2012

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	177	0.13%	177	0.13%	$4,124	0.05%	$4,124	0.05%
2	176	0.12%	353	0.25%	$3,514	0.04%	$7,637	0.08%
3	179	0.13%	532	0.38%	$1,733	0.02%	$9,370	0.10%
4	220	0.16%	753	0.53%	$1,632	0.02%	$11,003	0.12%
5	227	0.16%	980	0.69%	$2,276	0.02%	$13,279	0.14%
6	291	0.21%	1,271	0.90%	$4,961	0.05%	$18,240	0.20%
7	2,371	1.67%	3,642	2.57%	$126,089	1.38%	$144,329	1.58%
8	3,793	2.68%	7,435	5.25%	$173,655	1.90%	$317,984	3.47%
9	4,501	3.18%	11,936	8.43%	$170,314	1.86%	$488,298	5.33%
10	4,373	3.09%	16,308	11.52%	$171,336	1.87%	$659,634	7.20%
11	4,291	3.03%	20,599	14.55%	$195,128	2.13%	$854,762	9.33%
12	5,112	3.61%	25,711	18.16%	$265,291	2.90%	$1,120,053	12.23%
13	8,254	5.83%	33,965	23.99%	$570,616	6.23%	$1,690,669	18.46%
14	12,652	8.94%	46,617	32.93%	$817,418	8.92%	$2,508,086	27.38%
15	17,002	12.01%	63,619	44.94%	$1,210,368	13.21%	$3,718,454	40.60%
16	18,234	12.88%	81,854	57.82%	$1,460,737	15.95%	$5,179,191	56.54%
17	18,782	13.27%	100,636	71.09%	$1,493,164	16.30%	$6,672,355	72.85%
18	18,306	12.93%	118,942	84.02%	$1,320,621	14.42%	$7,992,976	87.27%
19	8,984	6.35%	127,925	90.36%	$541,467	5.91%	$8,534,443	93.18%
20	6,333	4.47%	134,258	94.84%	$325,732	3.56%	$8,860,175	96.73%
21	3,607	2.55%	137,865	97.38%	$173,580	1.90%	$9,033,756	98.63%
22	2,044	1.44%	139,908	98.83%	$80,237	0.88%	$9,113,992	99.50%
23	942	0.67%	140,851	99.49%	$27,129	0.30%	$9,141,121	99.80%
24	718	0.51%	141,568	100.00%	$18,308	0.20%	$9,159,429	100.00%

Table 5-11 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): 2012

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	1,615	1.14%	1,615	1.14%	$8,663	0.09%	$8,663	0.09%
$25 to $50	77,574	54.80%	79,189	55.94%	$2,944,492	32.15%	$2,953,156	32.24%
$50 to $75	31,253	22.08%	110,442	78.01%	$1,898,881	20.73%	$4,852,036	52.97%
$75 to $100	11,442	8.08%	121,885	86.10%	$1,010,065	11.03%	$5,862,101	64.00%
$100 to $125	6,707	4.74%	128,592	90.83%	$788,321	8.61%	$6,650,422	72.61%
$125 to $150	4,179	2.95%	132,770	93.79%	$568,642	6.21%	$7,219,065	78.82%
$150 to $200	3,002	2.12%	135,773	95.91%	$505,094	5.51%	$7,724,159	84.33%
$200 to $250	3,028	2.14%	138,801	98.05%	$628,775	6.86%	$8,352,933	91.19%
$250 to $300	1,829	1.29%	140,630	99.34%	$471,562	5.15%	$8,824,495	96.34%
> $300	939	0.66%	141,568	100.00%	$334,934	3.66%	$9,159,429	100.00%

Following the implementation of Order 745 on April 1, 2012, demand resources were paid full LMP for any load reductions during hours they were dispatched. If the demand resources are cost effective as determined by a Net Benefits Test (NBT), they are eligible to receive the full LMP. The NBT is used to define a threshold point where net benefits of DR are considered to exceed the cost to load. The Net Benefits Test defined an average threshold of $24.80 from April through December 2012. Demand resources are not paid for any load reductions during hours where the LMP is below the Net Benefits Test threshold.

Load Management Program

Table 5-12 shows zonal monthly capacity credits paid during 2012 to ILR and DR resources.[15] Capacity revenue decreased by $156.0 million, or 32.0 percent, compared to the same period in 2011, from 487.1 million to 331.1 million in 2012. Credits from January to May are associated with participation in the 2011/2012 RPM delivery year, and credits from June are associated with participation in the 2012/2013 RPM delivery year. The decrease in capacity credits in 2012 is the result of a decrease in RPM clearing prices in the rest of RTO region. While prices increased for MAAC zones to $133.37, the rest of the PJM RTO cleared at $16.46 in the 2012/2013 delivery year, an 85 percent decrease from the RTO wide $110.04 clearing price in the 2011/2012 delivery year The decrease is also partially due to the end of the ILR program, as well as a decrease in available capacity due to the FERC order ending the ability to count reductions above peak load contribution.[16]

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.

Table 5-12 Zonal monthly capacity credits: 2012

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$343,831	$321,649	$343,831	$332,740	$343,831	$397,836	$411,097	$411,097	$397,836	$411,097	$397,836	$411,097	$4,523,777
AEP	$5,390,887	$5,043,088	$5,390,887	$5,216,988	$5,390,887	$411,388	$425,101	$425,101	$411,388	$425,101	$411,388	$425,101	$29,367,303
AP	$3,410,799	$3,190,748	$3,410,799	$3,300,774	$3,410,799	$179,495	$185,478	$185,478	$179,495	$185,478	$179,495	$185,478	$18,004,316
ATSI	$4,821	$4,510	$4,821	$4,665	$4,821	$19,218	$19,859	$19,859	$19,218	$19,859	$19,218	$19,859	$160,724
BGE	$3,630,571	$3,396,340	$3,630,571	$3,513,455	$3,630,571	$5,254,943	$5,430,108	$5,430,108	$5,254,943	$5,430,108	$5,254,943	$5,430,108	$55,286,766
ComEd	$6,180,266	$5,781,539	$6,180,266	$5,980,903	$6,180,266	$392,831	$405,926	$405,926	$392,831	$405,926	$392,831	$405,926	$33,105,439
DAY	$824,485	$771,293	$824,485	$797,889	$824,485	$61,616	$63,670	$63,670	$61,616	$63,670	$61,616	$63,670	$4,482,166
DEOK	$0	$0	$0	$0	$0	$7,921	$8,185	$8,185	$7,921	$8,185	$7,921	$8,185	$56,500
DLCO	$2,418	$2,262	$2,418	$2,340	$2,418	$48,114	$49,718	$49,718	$48,114	$49,718	$48,114	$49,718	$355,071
Dominion	$3,977,804	$3,721,172	$3,977,804	$3,849,488	$3,977,804	$297,028	$306,929	$306,929	$297,028	$306,929	$297,028	$306,929	$21,622,872
DPL	$817,336	$764,605	$817,336	$790,970	$817,336	$1,497,145	$1,547,049	$1,547,049	$1,497,145	$1,547,049	$1,497,145	$1,547,049	$14,687,215
JCPL	$883,220	$826,238	$883,220	$854,729	$883,220	$1,447,382	$1,495,628	$1,495,628	$1,447,382	$1,495,628	$1,447,382	$1,495,628	$14,655,283
Met-Ed	$909,516	$850,837	$909,516	$880,176	$909,516	$1,010,595	$1,044,281	$1,044,281	$1,010,595	$1,044,281	$1,010,595	$1,044,281	$11,668,469
PECO	$2,375,286	$2,222,042	$2,375,286	$2,298,664	$2,375,286	$2,574,260	$2,660,069	$2,660,069	$2,574,260	$2,660,069	$2,574,260	$2,660,069	$30,009,621
PENELEC	$1,380,240	$1,291,192	$1,380,240	$1,335,716	$1,380,240	$1,107,926	$1,144,857	$1,144,857	$1,107,926	$1,144,857	$1,107,926	$1,144,857	$14,670,832
Pepco	$1,174,938	$1,099,136	$1,174,938	$1,137,037	$1,174,938	$1,845,088	$1,906,591	$1,906,591	$1,845,088	$1,906,591	$1,845,088	$1,906,591	$18,922,612
PPL	$2,739,610	$2,562,861	$2,739,610	$2,651,235	$2,739,610	$3,142,521	$3,247,272	$3,247,272	$3,142,521	$3,247,272	$3,142,521	$3,247,272	$35,849,577
PSEG	$1,468,327	$1,373,596	$1,468,327	$1,420,962	$1,468,327	$2,278,452	$2,354,400	$2,354,400	$2,278,452	$2,354,400	$2,278,452	$2,354,400	$23,452,497
RECO	$22,526	$21,072	$22,526	$21,799	$22,526	$14,415	$14,896	$14,896	$14,415	$14,896	$14,415	$14,896	$213,275
Total	$35,536,881	$33,244,179	$35,536,881	$34,390,530	$35,536,881	$21,988,172	$22,721,111	$22,721,111	$21,988,172	$22,721,111	$21,988,172	$22,721,111	$331,094,314

15 ILR ended after the 2011/2012 DY.

16 137 FERC ¶ 61,108

Table 5-13 shows registered MW in the Load Management Program by program type for delivery years 2007/2008 through 2012/2013. Due to the end of the ILR program and the FERC order on measurement and verification, available demand response capacity decreased during the 2012/2013 delivery year.

The MMU has reported that a significant percentage of demand resources that clear in base residual auctions buy out of those positions in incremental auctions.[17] This has raised the issue of whether demand resources and generation resources commit to providing a physical resource when they offer capacity in a base residual auction. The tariff makes it clear that the specific resources must be identified when offering in capacity auctions.

Table 5-13 Registered MW in the Load Management Program by program type: Delivery years 2007/2008 through 2012/2013

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,020.5	6,273.8	7,294.3
2010/2011	1,070.0	7,982.4	9,052.4
2011/2012	2,792.1	8,730.5	11,522.7
2012/2013	7,449.3	0.0	7,449.3

Load Management Event Reported Compliance

In calendar year 2012, PJM declared two Load Management events, on July 17 and 18, 2012. These events affected resources committed for the 2012/2013 Delivery Year. Since each of these events occurred within the summer compliance period, each was considered in compliance assessment. Table 5-14 lists Load Management Events declared by PJM in 2012 and the affected zones.

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. It is not clear that short lead or long lead time resources are dispatched differently, though it is the case that not all resources will be dispatched for every event in some zones. As a result, the nominal ICAP stated in event compliance tables in this section will not equal total nominal ICAP for the zone, as not all resources were called in each zone during the events. Approximately 97.6 percent of registrations, accounting for 87.1 percent of registered MW, are designated as long lead time resources.

There were no events in 2012 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 events will again be required by PJM beginning with the 2014/2015 delivery year, but are currently voluntary only. 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 5-14 PJM declared Load Management Events: 2012

Event Date	Event Times	Delivery Year	Lead Time	Geographical area
17-Jul-12	HE 1700 - 1900	2012/2013	Long Lead	AEP, Dominion
18-Jul-12	HE 1600 - 1800	2012/2013	Long Lead	BGE, DPL, JCPL, PECO, PENELEC, Pepco
18-Jul-12	HE 1600 - 1800	2012/2013	Short Lead	AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG

17 For more detail on the replacement capacity issue see: the *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market," "*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 11, 2012), and "Definition of DR Commitment in Auctions," IMM presentation to the DR Plan Enhancements Meeting (February 14, 2013) <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_DRPE_Definition_of_DR_Commitment_in_Auctions_20130214.pdf >.

Table 5-15 Load Management event performance: July 17, 2012

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AEP	1,201.5	1,045.6	1,101.2	55.7	105.3%	91.6%
Dominion	663.8	624.4	635.4	11.0	101.8%	95.7%
Total	1,865.3	1,669.9	1,736.6	66.6	104.0%	93.1%

Table 5-15 shows performance for the July 17, 2012 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 104.0 percent, or 1,736.6 MW out of 1,669.9 MW committed. AEP showed the highest MW reduction with 1,101.2 MW in observed load reduction or 63.4 percent of the total load reduction during the event, as well as the highest aggregate performance percentage of 105.3 percent. This reported performance value treated locations showing negative performance as zero performance.

Table 5-16 shows performance for the July 18, 2012 event. Overall, the performance was 103.3 percent, or 4,352.5 MW out of 4,214.6 MW committed. BGE showed the highest MW reduction with 817.6 MW of total load reduction observed. Met-Ed showed the highest aggregated performance of 141.1 percent. The PSEG Zone had poor performance with 10.6 percent compliance, though most PSEG customers are long lead time resources and most MW were not called in the PSEG Zone. This reported performance value treated locations showing negative performance as zero performance.

Table 5-16 Load Management event performance: July 18, 2012

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	37.4	32.3	36.1	3.8	111.9%	96.6%
BGE	861.1	794.2	817.6	23.4	103.0%	95.0%
BGE Short Lead	92.2	89.7	90.6	1.0	101.1%	98.3%
BGE Long Lead	768.9	704.5	727.0	22.5	103.2%	94.6%
DPL	197.2	173.5	161.2	(12.3)	92.9%	81.8%
DPL Short Lead	52.6	46.7	48.4	1.7	103.7%	92.0%
DPL Long Lead	144.6	126.8	112.8	(14.0)	89.0%	78.0%
JCPL	190.9	165.4	192.9	27.5	116.6%	101.1%
JCPL Short Lead	24.7	24.4	31.4	7.0	128.6%	127.1%
JCPL Long Lead	166.2	141.0	161.5	20.5	114.5%	97.2%
Met-Ed	11.6	11.0	15.5	4.5	141.1%	133.5%
PECO	442.5	401.4	408.8	7.4	101.9%	92.4%
PECO Short Lead	0.7	0.7	0.4	(0.2)	63.9%	59.5%
PECO Long Lead	441.8	400.7	408.4	7.7	101.9%	92.4%
PENELEC	297.7	236.4	238.0	1.6	100.7%	79.9%
PENELEC Short Lead	0.3	0.2	0.1	(0.1)	26.5%	16.0%
PENELEC Long Lead	297.4	236.2	237.9	1.8	100.7%	80.0%
Pepco	381.0	308.8	330.9	22.1	107.1%	86.8%
Pepco Short Lead	136.8	107.2	136.6	29.3	127.4%	99.9%
Pepco Long Lead	244.3	201.6	194.3	(7.3)	96.4%	79.5%
PPL	1.9	1.8	1.0	(0.8)	56.2%	55.5%
PSEG	20.0	10.1	1.1	(9.0)	10.6%	5.4%
Total	4,811.7	4,214.6	4,352.5	138.0	103.3%	90.5%

Table 5-17 shows load management event performance for the two event days. RTO wide percent compliance was 103.1 percent in 2012 for resources called during emergency events. This reported performance value treated locations showing negative performance as zero performance.

Table 5-17 Load Management event performance: 2012 Aggregate

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	37.4	32.3	36.1	3.8	111.9%	96.6%
AEP	1,201.5	1,045.6	1,101.2	55.7	105.3%	91.6%
BGE	861.1	794.2	817.6	23.4	103.0%	95.0%
Dominion	663.8	624.4	635.4	11.0	101.8%	95.7%
DPL	197.2	173.5	144.0	(29.5)	83.0%	73.0%
JCPL	190.9	165.4	192.9	27.5	116.6%	101.1%
Met-Ed	11.6	11.0	15.5	4.5	141.1%	133.5%
PECO	442.5	401.4	408.8	7.4	101.9%	92.4%
PENELEC	297.7	236.4	238.0	1.6	100.7%	79.9%
Pepco	381.0	308.8	330.9	22.1	107.1%	86.8%
PPL	1.9	1.8	1.0	(0.8)	56.2%	55.5%
PSEG	20.0	10.1	1.1	(9.0)	10.6%	5.4%
Total	4,306.7	3,804.8	3,922.5	117.7	103.1%	91.1%

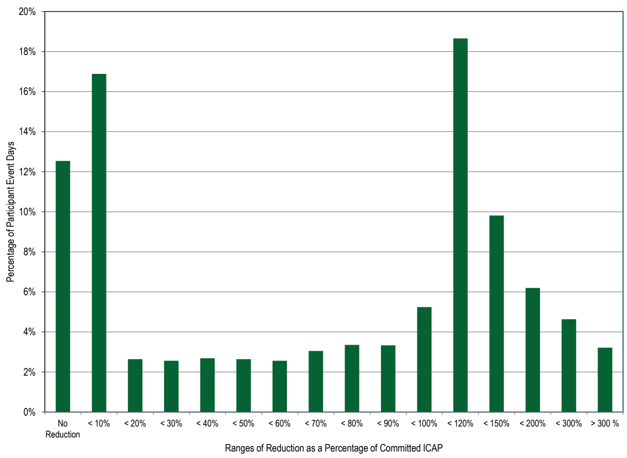
Performance for specific customers varied significantly. Table 5-18 shows the distribution of participant event days across various levels of performance for July 17 and July 18, 2012, events in the 2012/2013 compliance period. For these events, approximately 29 percent of participants showed little or no reduction. Approximately 40 percent of participants did not meet half of their committed MW. The majority of participants, approximately 57 percent, showed less than 100 percent reduction compared to their commitment. Figure 5-3 shows the data in Table 5-18.[18] The distribution includes high frequencies of both under performing and over performing registrations. This large disparity in performance indicates over compliance of some resources is making up for the non-response of resources to emergency events. This indicates that negative load reductions (load increase) are not treated appropriately for event compliance, and current rules should be modified to more accurately reflect event compliance.

Table 5-18 Distribution of participant event days across ranges of performance levels across the event in the 2012/2013 Delivery Year compliance period

Ranges of performance as a percentage of committed MW	Number of participant event days	Proportion of participant event days	Cumulative Proportion
0% or load increase	617	13%	13%
0% -10%	831	17%	29%
10% - 20%	130	3%	32%
20% - 30%	126	3%	35%
30% - 40%	132	3%	37%
40% - 50%	130	3%	40%
50% - 60%	126	3%	43%
60% - 70%	150	3%	46%
70% - 80%	165	3%	49%
80% - 90%	164	3%	52%
90% - 100%	258	5%	57%
100% - 120%	918	19%	76%
120% - 150%	483	10%	86%
150% - 200%	305	6%	92%
200% - 300%	228	5%	97%
> 300%	158	3%	100%
Total	4,921	100%	

18 Participant event days, shown in Figure 5-3, and Table 5-18, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant even day. In addition, 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 5-3 Distribution of participant event days across ranges of performance levels across the event in the 2012/2013 Delivery Year compliance period



GLD customers, in years prior to the 2012/2013 delivery year, reported reductions which were greater than their PLCs. This was not consistent with economic logic or the design of the program. This practice was ended by a FERC order on the measurement and verification of demand response, effective with the 2012/2013 delivery year.[19] The results for the events occurring during the summer, which fell in the 2012/2013 delivery year, show that the FERC order was effective in ending this practice. Table 5-19 shows the distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of PLC for all events in the 2012/2013 Delivery Year. The results in Table 5-19 show the distribution of GLD participant event hours and observed load reductions as a percentage of the location's PLC. Load reductions greater than PLC no longer count for event compliance, and are counted as a reduction up to the PLC value. The issue of GLD customers reporting reductions greater than their PLCs has been eliminated with the imposition of the PLC cap on load response MW.

Load Management Analysis

Currently, load management event rules allow overcompliance to be reported when there is no actual overcompliance. 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 25 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, 23 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, 6.5 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 as treated as zero for the purposes of imposing penalties and reporting.

Table 5-20 shows load management event performance, explicitly netting out negative load reduction values that were reported. These reported negative values were

Table 5-19 Distribution of GLD participant event hours and observed load reductions across ranges of load reduction as a percentage of Peak Load Contribution (PLC) for the events in the 2012/2013 Delivery Year

Ranges of load reduction as a percentage of PLC	Number of GLD participant event hours	Proportion of total GLD participant event hours	Cumulative Proportion	Observed reductions (MWh)	Proportion of total GLD observed reductions	Cumulative Proportion
0% - 25%	170	9%	9%	0.0	0%	0%
25% - 50%	977	54%	64%	64.6	9%	9%
50% - 75%	269	15%	79%	209.1	30%	40%
75% - 100%	174	10%	88%	44.2	6%	46%
100%	210	12%	100%	367.6	54%	100%
Total	1,800	100%		685.5	100%	

19 137 FERC ¶ 61,108

set to zero in PJM's reported compliance values, consistent with the rules. This analysis conservatively assumes that non-reporting locations were zero. Compliance decreases from 103.1 percent to 97.6 percent. Considering all and only reported values, the observed load reduction of the two events in 2012 was 3,713.4 MW, rather than the 3,922.5 MW reported. It is likely that these results still overstate compliance, as 444 locations did not report for 2012 event compliance. The PSEG Zone shows a negative performance of 32.7 percent as some resources in this zone increased their load during emergency event hours.

Table 5-21 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 for multiple zones. Actual compliance for the Dominion zone was 96.7 percent rather than 101.8 percent. Actual compliance for the JCPL zone was 69.6 percent rather than 116.6 percent. Actual compliance for the PECO Zone was 97.5 percent rather than 101.9 percent. Actual compliance for the PENELEC Zone was 95.8 percent rather than 100.7 percent.

Table 5-22 shows the number of locations attached to registrations that did not report during 2012 event days. In total, 6.5 percent of locations did not report during event days in 2012 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 5-20 Load Management Event Performance with negatives: 2012

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	37.4	32.3	36.1	3.8	111.9%	96.6%
AEP	1,201.5	1,045.6	1,065.3	19.7	101.9%	88.7%
BGE	861.1	794.2	801.2	7.0	100.9%	93.0%
Dominion	663.8	624.4	603.9	(20.4)	96.7%	91.0%
DPL	197.2	173.5	144.0	(29.5)	83.0%	73.0%
JCPL	190.9	165.4	115.1	(50.3)	69.6%	60.3%
Met-Ed	11.6	11.0	15.5	4.5	141.1%	133.5%
PECO	442.5	401.4	391.3	(10.1)	97.5%	88.4%
PENELEC	297.7	236.4	226.5	(9.9)	95.8%	76.1%
Pepco	381.0	308.8	316.8	8.0	102.6%	83.2%
PPL	1.9	1.8	1.0	(0.8)	56.2%	55.5%
PSEG	20.0	10.1	(3.3)	(13.4)	(32.7%)	(16.5%)
Total	4,306.7	3,804.8	3,713.4	(91.4)	97.6%	86.2%

Table 5-21 Load Management Event Performance Comparison: Reported Reduction vs. Actual Reduction: 2012

Zone	Committed MW	Load Reduction Reported (MWh)	Actual Load Reduction (MWh)	Difference	Percent Compliance Reported	Percent Compliance Actual
AECO	32.3	36.1	36.1	0.0	111.9%	111.9%
AEP	1,045.6	1,101.2	1,065.3	36.0	105.3%	101.9%
BGE	794.2	817.6	801.2	16.5	103.0%	100.9%
Dominion	624.4	635.4	603.9	31.4	101.8%	96.7%
DPL	173.5	144.0	144.0	0.0	83.0%	83.0%
JCPL	165.4	192.9	115.1	77.8	116.6%	69.6%
Met-Ed	11.0	15.5	15.5	0.0	141.1%	141.1%
PECO	401.4	408.8	391.3	17.5	101.9%	97.5%
PENELEC	236.4	238.0	226.5	11.5	100.7%	95.8%
Pepco	308.8	330.9	316.8	14.0	107.1%	102.6%
PPL	1.8	1.0	1.0	0.0	56.2%	56.2%
PSEG	10.1	1.1	(3.3)	4.4	10.6%	(32.7%)
Total	3,804.8	3,922.5	3,713.4	209.1	103.1%	97.6%

Table 5-22 Non Reporting Locations on 2012 Event Days

Zone	Locations Not Reporting	Total Locations	Percent Non Reporting
AECO	2	15	13.3%
AEP	95	1,092	8.7%
BGE	60	810	7.4%
Dominion	46	760	6.1%
DPL	23	447	5.1%
JCPL	42	416	10.1%
Met-Ed	6	7	85.7%
PECO	104	1,308	8.0%
PENELEC	34	1,308	2.6%
Pepco	29	586	4.9%
PPL	0	23	0.0%
PSEG	3	28	10.7%
Total	444	6,800	6.5%

Table 5-23 shows the nominated capacity of nonreporting locations. Approximately 2.7 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 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.

Table 5-23 Non Reporting Locations by MW on 2012 Event Days

Zone	Nominated ICAP Not Reporting	Nominated ICAP	Percent Non Reporting
AECO	1.1	37.4	3.1%
AEP	27.4	1,201.5	2.3%
BGE	16.3	861.1	1.9%
Dominion	10.3	663.8	1.6%
DPL	6.3	197.2	3.2%
JCPL	10.2	190.9	5.3%
Met-Ed	1.0	11.6	8.3%
PECO	25.0	442.5	5.7%
PENELEC	6.0	297.7	2.0%
Pepco	12.0	381.0	3.1%
PPL	0.0	1.9	0.0%
PSEG	0.6	20.0	2.8%
Total	116.2	4,306.7	2.7%

Emergency Energy Payments

For any PJM declared Load Management event in 2012, 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 shortage pricing rules increases the maximum offer for the 2012/2013 DY to $1,500/MWh. The maximum offer increases to $1,800/MWh for the 2013/2014 DY, $2,100/MWh for the 2014/2015 and $2,700/MWh for the 2015/2016 DY. The maximum generator offer will stay constant at $1,000/MWh.

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 5-24 shows the distribution of registrations and associated MW in the Emergency Full Option across ranges of minimum dispatch prices. The majority of participants, 78.9 percent, have a minimum dispatch price of $999/MWh or higher. Energy offers are further increased by submitted shutdown costs, which, in the 2012/2013 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 $200 - $500 strike prices had the highest average at $765.77 per registration.

Shutdown cost currently is not adequately defined in Manual 15. The MMU recommends that shutdown cost should be defined as the cost to curtail load for a given period that does not vary with the measured reduction, or for behind the meter generators, should be equivalent to the start cost defined in Manual 15.

Table 5-24 Distribution of registrations and associated MW in the Emergency Full Option across ranges of Minimum Dispatch Prices effective for the 2012/2013 Delivery Year[20]

Ranges of Strike Prices ($/MWh)	Registrations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Registration
$0 - $1	1,047	12.1%	1,051.9	14.9%	$0.00
$1.01 - $200	227	2.6%	205.2	2.9%	$0.00
$200 - $500	520	6.0%	311.6	4.4%	$765.77
$500 - $998	37	0.4%	51.8	0.7%	$235.65
$999+	6,827	78.9%	5,417.8	77.0%	$41.84
Total	8,658	100.0%	7,038.2	100.0%	$79.99

Table 5-25 shows emergency credits and make whole payments for each event in 2012. 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.

Table 5-25 Emergency credits and make whole payments by event: 2012

Event	Emergency Credits	Emergency Make Whole Payments	Total
17-Jul-12	$1,010,372.27	$3,751,680.48	$4,762,052.75
18-Jul-12	$592,597.01	$5,126,683.66	$5,719,280.67
Total	$1,602,969.28	$8,878,364.14	$10,481,333.42

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. These payments are simply guaranteed offers which are not required to provide any documentation or justification.

Load Management Testing

In the 2007/2008 and the 2008/2009 delivery years, Load Management (LM) compliance was assessed only for actual PJM declared events. If no event was declared, no capacity testing was required. PJM filed amendments to the tariff providing for LM testing if no emergency event is called by August 15 of the delivery year, which became effective in the 2009/2010 delivery year. All of a provider's committed DR and certified ILR resources in the same zone are required to test at the same time for a one hour period between 12:00 PM EPT to 8:00 PM EPT on a non-holiday weekday between June 1 and September 30. The resource provider must notify PJM of the intent to test 48 hours in advance.[21]

Depending on initial test results, multiple tests may be conducted. If a Curtailment Service Provider (CSP) shows greater than or equal to 75 percent test compliance across a portfolio of resources, all noncompliant resources are eligible for retesting. However, if the initial test shows less than 75 percent compliance, no associated resources are eligible for a retest.

There were 3,639.4 MW of Committed ICAP not deployed in an event during the compliance period for the 2012/2013 Delivery year and thus required to perform testing. Load Management testing results are shown in Table 5-26. Overall, test results showed 568.8 MW available over RPM commitments, or 116 percent test compliance. The RECO Control Zone showed the highest percentage of compliance, with load reductions at 170 percent of RPM Commitments, while the ATSI Control Zone showed the highest level of MW reduction in testing, with load reductions at 971.7 MW, or 149.6 MW over RPM commitments.

Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to a baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification.

20 In this analysis Nominated MW does not include capacity only resources, which do not receive energy market revenue.

21 For more information, see PJM, "Manual 18, PJM Capacity Market," Revision 17 (December 20, 2012), Section 8.6.

Table 5-26 Load Management test results and compliance by zone for the 2012/2013 delivery year

Zone	Nominal ICAP	Committed MW	Load Reduction Test Results	Over/Under Compliance	Percent Test Compliance	Percent of Nominal ICAP
AECO	60.4	48.5	66.7	18.2	137%	110%
AEP	136.6	134.2	158.1	23.8	118%	116%
AP	543.2	481.7	539.6	57.9	112%	99%
ATSI	977.7	822.1	971.7	149.6	118%	99%
ComEd	809.9	755.8	805.5	49.7	107%	99%
DAY	102.5	84.5	95.6	11.1	113%	93%
DEOK	295.4	231.7	316.3	84.6	137%	107%
DLCO	110.4	80.4	97.6	17.2	121%	88%
Dominion	1.1	1.1	0.8	(0.3)	73%	73%
Met-Ed	185.5	158.6	196.7	38.1	124%	106%
PPL	623.6	542.8	609.6	66.9	112%	98%
PSEG	355.0	294.8	344.7	49.8	117%	97%
RECO	5.3	3.2	5.4	2.2	170%	102%
Total	4,206.6	3,639.4	4,208.2	568.8	116%	100%

This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. Given prior warning of a test event, customers have time to prepare to drop load, unlike in a real emergency event in which a customer will only have one to two hours' notice before an event begins. Customers can test on any day in the summer period, and choose any other day in that period to serve as the baseline consumption for estimating load reductions. There are no criteria to establish comparability between the baseline day and test day.

The MMU recommends that the testing program be modified to require verification of test methods and results. Tests should be initiated by PJM without prior scheduling by CSPs, in order to more accurately model demand response during an emergency event.

Resources are currently able to retest under certain conditions, and negative values are zeroed out for purposes of compliance. Table 5-27 shows test results without retests and including negative values, or measurement of load above the customer's baseline. This shows overall test compliance of approximately 112 percent, or 4 percent below the apparent reported compliance. With these changes, load management testing will more accurately reflect event day performance.

Table 5-27 Load Management Test Results with negatives, excluding retests

Zone	Nominal ICAP	Committed MW	Load Reduction Test Results	Over/Under Compliance	Percent Test Compliance	Percent of Nominal ICAP
AECO	60.4	48.5	57.8	9.3	119%	96%
AEP	136.6	134.2	158.1	23.8	118%	116%
AP	543.2	481.7	527.5	45.8	110%	97%
ATSI	977.7	822.1	948.3	126.2	115%	97%
ComEd	809.9	755.8	768.2	12.4	102%	95%
DAY	102.5	84.5	86.0	1.5	102%	84%
DEOK	295.4	231.7	314.5	82.8	136%	106%
DLCO	110.4	80.4	95.0	14.6	118%	86%
Dominion	1.1	1.1	0.8	(0.3)	73%	73%
Met-Ed	185.5	158.6	193.0	34.5	122%	104%
PPL	623.6	542.8	585.1	42.4	108%	94%
PSEG	355.0	294.8	328.7	33.9	111%	93%
RECO	5.3	3.2	5.1	1.9	159%	95%
Total	4,206.6	3,639.4	4,068.2	428.8	112%	97%

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 6 hours within a two hour window of PJM starting the event. When a provider under complies based on their registered MW, a penalty occurs 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.

Table 5-28 shows penalty charges by zone for the 2012/2013 DY. Met-Ed was the only zone that was called for an event that had no penalty charges.

Table 5-28 Penalty Charges per Zone: Delivery Year 2012/2013

	Penalty Charge
AECO	$53.50
AEP	$84,134.10
AP	$0.00
ATSI	$0.00
BGE	$78,475.94
ComEd	$0.00
DAY	$0.00
DEOK	$0.00
Dominion	$34,603.80
DPL	$434,306.58
DLCO	$0.00
JCPL	$3,126.54
Met-Ed	$0.00
PECO	$234,171.64
PENELEC	$25,836.22
Pepco	$293,680.76
PPL	$348.82
PSEG	$5,968.46
RECO	$0.00
Total	$1,194,706.36

Measurement and Verification

Since the beginning of the program, there have been significant issues with the approach to measuring demand-side response MW. An inaccurate or unrepresentative measurement protocol can lead to payments when the customer has taken no action to respond to market prices. Substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the customer base line calculation and/or improvements in the verification and customer documentation of load reducing activities. The goal should be to treat the measurement of demand-side resources like the measurement of any other resource in the wholesale power market, including generation and load, that is paid by other participants or makes payments to other participants. PJM has made changes to improve the settlement review process, but more needs to be done.[22]

In the future, retail markets will reflect hourly wholesale prices and customers will receive direct savings associated with reducing consumption in response to real-time prices. There will not be a need for a PJM Economic Load Response Program, or for an extensive measurement and verification protocol. In the transition to that point, there is a need for robust measurement and verification techniques to ensure that transitional programs are incenting the desired behavior. These techniques are designed to estimate what consumption would have been, absent any load reducing activities.

Customer Base Line Issues

The customer base line (CBL) is a generic formula applied to nearly every customer's usage and is not adequate to serve as the sole or primary basis for determining if an intentional load reduction took place. There are no mandatory CBL enhancements for customers with highly volatile load patterns. If a customer normally has lower load on one particular weekday, that day will appear as a reduction eligible for payment under the current CBL methodology although no deliberate load reducing actions were taken in response to real time price signals. There are no mandatory adjustments to the standard CBL for load levels that are a function of weather. In a mild week, following a week of extreme temperatures and high load levels, a customer can submit settlements without taking any load reducing action and it will appear as a reduction eligible for payment because metered load is below CBL. In the registration process, an alternative CBL may be proposed by the CSP or the relevant LSE/EDC, though following Order 745 changes, CBLs must undergo a Relative Root Mean Squared Error (RRMSE) test to determine the most accurate method.[23] PJM has developed thirteen alternative CBL calculations, three of which include a weather sensitivity adjustment.

22 123 FERC ¶ 61,257 (2008).
23 If, however, agreement cannot be reached, then PJM will determine the alternative CBL.

Determining the accuracy of a CBL is difficult. More data are required than the metered load associated with settlement and the CBL used to determine the reduction amount. However, those are the only data currently available to PJM at the time of settlement review. Complete historical metered load data is required in order to determine whether the CBL is representative of normal load patterns.

Load Management Program

There have been three approaches to measurement and verification of resources in the load management program. The most common is specifying a firm MW level to which usage will be reduced, termed Firm Service Level (FSL). The less common approach for capacity resources is to establish a base line usage level by analyzing prior usage levels for a set of days that are intended to be representative of or similar to the day of the reduction. In the Load Management Program, this measurement and verification option is called Guaranteed Load Drop (GLD) and there are several baseline methods to choose from. The least common method is called Direct Load Control (DLC), which relies on direct LSE or CSP action to cause a customer to drop load.

FSL customers establish a firm consumption level which they must reach during an emergency event and the difference between that firm service level and the Peak Load Contribution (PLC) is the amount nominated in the LM Program. FSL customers are contractually obligated to reduce load to a nominal value. The measurement and verification of load reductions under FSL option for purposes of event compliance is relatively straightforward.

GLD customers establish a baseline of unrestricted consumption absent the emergency event, similar to the measurement and verification procedure in the Economic Program. The load reduction for GLD customers is the reduction of committed MW when an event is called. There are several techniques for estimation available to participants. The comparable day option determines reductions based on consumption on similar day experience. Another option determines reduction as differences from hourly load immediately prior to or following an event. A third option is the standard CBL calculation used in the Economic Program. Other options include regression analysis and load profile modeling. Following the implementation of the FERC order on measurement and verification, GLD customers no longer can count load reductions greater than their PLC value.

For DLC customers, load reductions are estimated through PJM reported or site surveyed impact studies. No telemetry or load data are required for verification of actual event performance. Rather, the CSP submits to PJM the time at which the equipment is deployed. There is no way for PJM or the MMU to determine if any load reduction took place in an emergency event.

The MMU recommends that the compliance rules in the Load Management Program be improved. CSPs should be required to submit metered load for all locations called during an emergency event. Non-responding resources with load increases during events should be included and netted against positively performing resources within a CSP's portfolio. The testing protocols are also inadequate, in that they do not simulate an event day. Tests should be initiated by PJM on a zonal basis by CSP, and not planned in advance by CSPs. Barring those changes; there should be no allowance to re-test resources. The MMU recommends refinement of the baseline methods used to calculate compliance in Load Management for GLD customers. The baseline pilot study conducted by KEMA indicated that the CBL used by the PJM Economic Program is an improvement, and consequently should be used by the GLD option in the Load Management Program.

Economic Program

In the Economic Program, the baseline method is the default approach, and the standard baseline is referred to as Customer Baseline Load (CBL).

In PJM's Economic Load Response Program, the primary tool used to establish what unrestricted load would have been is the default CBL with Symmetrical Additive Adjustment. The modifications to the CBL calculations currently occurring represent significant improvements to the Economic Program, but the review process is not yet adequate to ensure that other customers are receiving the benefit of actual demand reductions when payments are made under the program. The default CBL is now the CBL with Symmetrical Additive Adjustment (SAA), which incorporates a same day adjustment to minimize the inherent variability in the measurement of load reductions. In addition, to further limit variability inherent in the measurement process, all registrations for locations participating in energy programs must submit a Relative Root Mean Squared Error (RRMSE) analysis of sample load data for each location. The RRMSE must be less than 20 percent. A protocol submitted as part of the registration process must have a RRMSE of less than 20 percent and be more accurate than the CBL with SAA.

The definition of the standard or default CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions.

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), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- Net revenues are significantly affected by energy prices, fuel prices and capacity prices. Revenue from the capacity market was lower in 2012 in all zones except DPL and PSEG. The combination of these factors resulted in lower total net revenues for the new entrant CT in all zones, for the new entrant CC in all zones and for the new entrant CP in all zones. The total net revenues for an IGCC plant, a nuclear plant, a solar installation and a wind installation were also affected by lower energy revenues and lower capacity revenues in 2012.
- The total net revenues did not cover the annual levelized fixed costs of a new entrant CT in any zone. The total net revenues covered the annual levelized fixed costs of a new entrant CC in three zones and covered more than 90 percent of annual levelized fixed costs in nine of 16 relevant zones. The total net revenues did not cover the annual levelized fixed costs of a new entrant CP in any zone and did not exceed 20 percent of the annual levelized fixed costs of a new entrant CP in any zone.
- The total net revenues covered only five percent of the annual levelized fixed costs of a new entrant IGCC. The total net revenues covered only 28 percent of the annual levelized fixed costs of a new entrant nuclear plant. The total net revenues covered more than 65 percent of the annual levelized fixed costs of a new entrant wind installation. The total net revenues covered 97 percent of the annual levelized fixed costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for more than 40 percent of the net revenue of a wind installation and more than 80 percent of the net revenue of a solar installation.
- Of existing sub-critical coal units, 39 percent did not recover even avoidable costs from total net revenues and of existing supercritical coal units, 15 percent did not recover even avoidable costs from total net revenues. Coal units that have not declared their intent to retire and did not cover avoidable costs from total market revenues comprise 3,725 MW of capacity. These units can be considered to be at risk of retirement.

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.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to nonmarket and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

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.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

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.

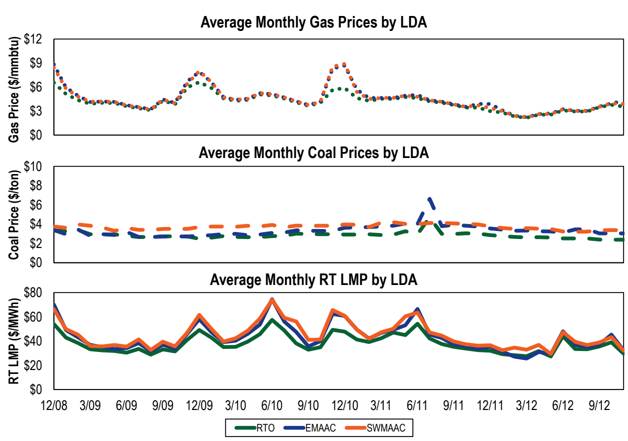
In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute 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 system average LMP was 22.7 percent lower in 2012 than in 2011. Both coal and natural gas decreased in price in 2012. Comparing prices in 2012 to prices in 2011, the price of Northern Appalachian coal was 16.5 percent lower; the price of Central Appalachian coal was 18.4 percent lower; the price of Powder River Basin coal was 31.5 percent lower; the price of eastern natural gas was 36.2 percent lower; and the price of western natural gas was 31.9 percent lower.[2] Revenue from the capacity market was lower in 2012 in all zones except DPL and PSEG.

The combination of these factors resulted in lower total net revenues for the new entrant CT in all zones, for the new entrant CC in all zones and for the new entrant CP in all zones. The total net revenues for an IGCC plant, a nuclear plant, a solar installation and a wind installation were also affected by lower energy revenues and lower capacity revenues in 2012.

Figure 6-1 Energy Market net revenue factor trends: December 2008 through December 2012



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 the economic dispatch scenario.

Analysis of Energy Market net revenues for a new entrant includes seven 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 NOx 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 NOx reduction with a single steam turbine generator.[3]
- The coal plant is a sub-critical steam CP, equipped with selective catalytic reduction system (SCR) for NOx control, a Flue Gas Desulphurization (FGD) system with chemical injection for SOx 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 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 hourly local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4,5] Plant heat rates were calculated for each hour to account for the

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.

2 All fuel prices are from Platts.

3 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.

4 Hourly ambient conditions supplied by Schneider Electric.

5 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.

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.[6]

A forced outage rate for each class of plant was calculated from PJM data.[7] 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 three 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 the reference CT plant configuration in either costs or revenues or for any of the other plant 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.

6 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

7 Outage figures obtained from the PJM eGADS database. The CC outage rate was used for the IGCC plant.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[8] 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 basis adjustment for transportation costs.[9] 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.[10]

Operating costs are the marginal cost of operations and include fuel costs, emissions costs, and VOM costs. Average zonal operating costs in 2012 for a CT were $38.85 per MWh, based on a design heat rate of 10,241 Btu per kWh and a VOM rate of $8.34 per MWh. Average zonal operating costs for a CP were $30.65 per MWh, based on a design heat rate of 9,250 Btu per kWh and a VOM rate of $3.29 per MWh. Average zonal operating costs for a CC were $22.45 per MWh, based on a design heat rate of 7,127 Btu per kWh and a VOM rate of $1.50 per MWh. Average zonal operating costs for an IGCC were $36.51 per MWh, based on a design heat rate of 9,407 Btu per kWh and a VOM rate of $6.89 per MWh. VOM expenses include accrual of anticipated, routine major overhaul expenses.[11]

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.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. Capacity revenue for 2012 includes five months of the 2011/2012 RPM auction clearing price and seven months of the 2012/2013 RPM

8 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.

9 Gas daily cash prices obtained from Platts.

10 Coal prompt prices obtained from Platts.

11 VOM rates provided by Pasteris Energy, Inc.

auction clearing price.[12] These capacity revenues are adjusted for the yearly, system wide forced outage rate.[13]

Table 6-1 Capacity revenue by PJM zones[14] (Dollars per MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Average
AECO	$58,586	$61,406	$45,938	$43,138	$52,267
AEP	$35,789	$48,898	$45,938	$18,730	$37,339
AP	$53,440	$61,406	$45,938	$18,730	$44,878
ATSI	NA	NA	NA	NA	NA
BGE	$76,236	$67,851	$45,938	$41,878	$57,976
ComEd	$35,789	$48,898	$45,938	$18,730	$37,339
DAY	$35,789	$48,898	$45,938	$18,730	$37,339
DEOK	NA	NA	NA	NA	NA
DLCO	$35,789	$48,898	$45,938	$18,730	$37,339
Dominion	$35,789	$48,898	$45,938	$18,730	$37,339
DPL	$58,586	$62,251	$46,530	$48,399	$53,941
JCPL	$58,586	$61,406	$45,938	$43,138	$52,267
Met-Ed	$53,440	$61,406	$45,938	$41,878	$50,666
PECO	$58,586	$61,406	$45,938	$43,138	$52,267
PENELEC	$53,440	$61,406	$45,938	$41,837	$50,655
Pepco	$76,236	$67,851	$45,938	$41,878	$57,976
PPL	$53,440	$61,406	$45,938	$41,878	$50,666
PSEG	$58,586	$61,406	$45,938	$46,223	$53,038
RECO	NA	NA	NA	NA	NA
PJM	$48,385	$56,226	$45,956	$30,354	$45,230

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 6-2 PJM-wide net revenue for a CT under economic dispatch by market (Dollars per installed MW-year): 2009 through 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$9,945	$47,188	$0	$0	$887	$58,020
2010	$32,781	$55,186	$0	$0	$4,320	$92,287
2011	$36,104	$45,972	$0	$0	$3,587	$85,664
2012	$23,240	$30,116	$0	$0	$891	$54,246

Table 6-3 Energy Market net revenue[15] for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$12,421	$40,037	$46,157	$24,993	(46%)
AEP	$3,696	$11,575	$20,839	$16,263	(22%)
AP	$11,136	$32,494	$32,958	$21,029	(36%)
ATSI	NA	NA	NA	$18,296	NA
BGE	$15,126	$52,411	$48,642	$36,307	(25%)
ComEd	$2,445	$9,446	$15,081	$13,780	(9%)
DAY	$3,313	$11,701	$21,705	$18,573	(14%)
DEOK	NA	NA	NA	$16,004	NA
DLCO	$4,471	$17,525	$24,179	$18,773	(22%)
Dominion	$15,253	$42,922	$38,945	$25,375	(35%)
DPL	$13,886	$40,530	$44,339	$32,587	(27%)
JCPL	$11,994	$39,409	$44,968	$24,117	(46%)
Met-Ed	$11,083	$39,409	$40,802	$25,396	(38%)
PECO	$10,611	$38,311	$45,853	$25,884	(44%)
PENELEC	$6,986	$24,309	$32,090	$22,463	(30%)
Pepco	$17,798	$50,906	$44,233	$32,011	(28%)
PPL	$10,045	$33,649	$42,872	$22,817	(47%)
PSEG	$10,079	$37,626	$37,929	$24,081	(37%)
RECO	$8,717	$35,022	$32,178	$22,808	(29%)
PJM	$9,945	$32,781	$36,104	$23,240	(36%)

Table 6-4 Zonal combined net revenue from all markets for a CT under economic dispatch (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$70,445	$104,628	$95,698	$68,683	(28%)
AEP	$39,487	$63,889	$70,380	$35,737	(49%)
AP	$64,142	$97,085	$82,498	$40,503	(51%)
ATSI	NA	NA	NA	NA	NA
BGE	$90,364	$123,328	$98,182	$78,747	(20%)
ComEd	$38,235	$61,760	$64,622	$33,254	(49%)
DAY	$39,104	$64,015	$71,246	$38,047	(47%)
DEOK	NA	NA	NA	NA	NA
DLCO	$40,261	$69,839	$73,719	$38,247	(48%)
Dominion	$51,043	$95,237	$88,486	$44,849	(49%)
DPL	$71,910	$105,950	$94,472	$81,497	(14%)
JCPL	$70,018	$103,999	$94,509	$67,807	(28%)
Met-Ed	$64,089	$103,999	$90,342	$67,837	(25%)
PECO	$68,635	$102,902	$95,394	$69,574	(27%)
PENELEC	$59,992	$88,900	$81,631	$64,862	(21%)
Pepco	$93,036	$121,823	$93,774	$74,451	(21%)
PPL	$63,051	$98,240	$92,412	$65,258	(29%)
PSEG	$68,103	$102,217	$87,469	$70,832	(19%)
RECO	NA	NA	NA	NA	NA
PJM	$58,020	$92,287	$85,664	$54,246	(37%)

12 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant Base Residual Auctions.

13 The PJM capacity revenues differ slightly from those presented in Table 6-2, Table 6-5 and Table 6-8 as these capacity revenues by technology type are adjusted for technology-specific outage rates.

14 No resources in ATSI cleared in the relevant auctions. There are no capacity resources in the RECO zone.

15 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.[16] 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 6-5 PJM-wide net revenue for a CC under economic dispatch by market (Dollars per installed MW-year): 2009 through 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$52,260	$50,184	$0	$0	$1,641	$104,085
2010	$89,027	$58,324	$0	$0	$762	$148,113
2011	$106,618	$48,306	$0	$0	$964	$155,889
2012	$97,260	$31,422	$0	$0	$1,608	$130,290

Table 6-6 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$62,063	$106,643	$126,869	$101,124	(20%)
AEP	$29,759	$47,591	$82,324	$87,908	7%
AP	$59,052	$91,032	$113,561	$100,499	(12%)
ATSI	NA	NA	NA	$94,387	NA
BGE	$70,571	$124,665	$130,806	$123,367	(6%)
ComEd	$20,613	$33,906	$46,293	$61,754	33%
DAY	$27,904	$46,647	$82,067	$93,517	14%
DEOK	NA	NA	NA	$82,044	NA
DLCO	$27,649	$51,180	$81,642	$89,180	9%
Dominion	$68,932	$116,873	$114,530	$103,610	(10%)
DPL	$64,321	$106,245	$123,599	$114,808	(7%)
JCPL	$61,477	$105,474	$124,878	$100,386	(20%)
Met-Ed	$55,400	$97,665	$111,653	$96,018	(14%)
PECO	$57,843	$99,951	$121,804	$98,151	(19%)
PENELEC	$48,876	$80,773	$109,048	$106,236	(3%)
Pepco	$71,959	$121,952	$121,143	$115,691	(5%)
PPL	$52,285	$87,314	$111,111	$91,727	(17%)
PSEG	$57,910	$101,819	$114,951	$96,617	(16%)
RECO	$51,808	$93,724	$96,235	$90,924	(6%)
PJM	$52,260	$89,027	$106,618	$97,260	(9%)

Table 6-7 Zonal combined net revenue from all markets for a CC under economic dispatch (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$124,469	$171,103	$176,119	$147,387	(16%)
AEP	$68,520	$99,077	$131,574	$108,905	(17%)
AP	$116,122	$155,492	$162,812	$121,495	(25%)
ATSI	NA	NA	NA	NA	NA
BGE	$151,283	$195,811	$180,056	$168,326	(7%)
ComEd	$59,374	$85,392	$95,544	$82,751	(13%)
DAY	$66,664	$98,133	$131,317	$114,513	(13%)
DEOK	NA	NA	NA	NA	NA
DLCO	$66,409	$102,666	$130,892	$110,177	(16%)
Dominion	$107,693	$168,359	$163,780	$124,606	(24%)
DPL	$126,726	$171,582	$173,472	$166,517	(4%)
JCPL	$123,883	$169,934	$174,128	$146,649	(16%)
Met-Ed	$112,470	$162,125	$160,903	$140,977	(12%)
PECO	$120,248	$164,411	$171,054	$144,414	(16%)
PENELEC	$105,945	$145,233	$158,298	$151,152	(5%)
Pepco	$152,672	$193,098	$170,394	$160,650	(6%)
PPL	$109,354	$151,773	$160,361	$136,687	(15%)
PSEG	$120,316	$166,279	$164,201	$146,074	(11%)
RECO	NA	NA	NA	NA	NA
PJM	$104,085	$148,113	$155,889	$130,290	(16%)

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 6-8 PJM-wide net revenue for a CP by market (Dollars per installed MW-year): 2009 through 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$62,062	$47,469	$0	$2,213	$286	$112,029
2010	$119,478	$54,670	$0	$898	$601	$175,648
2011	$73,178	$44,282	$0	$1,029	$272	$118,760
2012	$34,408	$29,326	$0	$1,154	$117	$65,006

16 All starts associated with combined cycle units are assumed to be hot starts.

Table 6-9 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$87,901	$149,022	$75,325	$23,301	(69%)
AEP	$19,251	$56,227	$72,858	$41,244	(43%)
AP	$49,303	$98,671	$99,020	$54,552	(45%)
ATSI	NA	NA	NA	$47,274	NA
BGE	$46,299	$80,689	$56,940	$23,390	(59%)
ComEd	$42,738	$106,599	$94,493	$53,813	(43%)
DAY	$27,905	$77,082	$65,842	$43,027	(35%)
DEOK	NA	NA	NA	$36,519	NA
DLCO	$22,971	$76,395	$47,075	$43,904	(7%)
Dominion	$46,756	$144,290	$77,310	$17,547	(77%)
DPL	$38,833	$147,279	$94,908	$29,102	(69%)
JCPL	$74,389	$147,559	$71,437	$30,517	(57%)
Met-Ed	$57,888	$139,228	$61,703	$38,561	(38%)
PECO	$78,602	$142,542	$74,834	$24,474	(67%)
PENELEC	$77,650	$122,426	$95,440	$52,897	(45%)
Pepco	$70,058	$160,627	$73,476	$23,706	(68%)
PPL	$71,601	$114,549	$76,697	$18,079	(76%)
PSEG	$171,879	$124,533	$47,550	$22,590	(52%)
RECO	$71,025	$143,410	$59,111	$29,258	(51%)
PJM	$62,062	$119,478	$73,178	$34,408	(53%)

Table 6-10 Zonal combined net revenue from all markets for a CP (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$147,643	$209,652	$120,857	$66,479	(45%)
AEP	$57,078	$104,980	$118,055	$60,207	(49%)
AP	$104,183	$159,395	$144,140	$73,443	(49%)
ATSI	NA	NA	NA	NA	NA
BGE	$123,964	$148,075	$102,287	$65,248	(36%)
ComEd	$80,652	$155,257	$139,564	$72,912	(48%)
DAY	$65,610	$125,687	$111,028	$61,975	(44%)
DEOK	NA	NA	NA	NA	NA
DLCO	$60,794	$125,098	$92,186	$62,985	(32%)
Dominion	$84,483	$192,785	$122,827	$37,138	(70%)
DPL	$99,256	$208,730	$140,942	$77,234	(45%)
JCPL	$134,223	$208,178	$116,745	$73,383	(37%)
Met-Ed	$112,840	$199,873	$106,902	$80,076	(25%)
PECO	$138,387	$203,180	$119,999	$67,537	(44%)
PENELEC	$132,233	$183,038	$140,378	$94,165	(33%)
Pepco	$147,296	$227,527	$118,615	$65,493	(45%)
PPL	$126,399	$175,270	$121,869	$59,997	(51%)
PSEG	$231,098	$185,214	$93,675	$68,664	(27%)
RECO	NA	NA	NA	NA	NA
PJM	$112,015	$175,164	$118,488	$64,889	(45%)

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 6-11 Net revenue for an IGCC by market (Dollars per installed MW-year): 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2012	$13,130	$19,388	$0	$0	$1,608	$34,126

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 6-12 Net revenue for a nuclear plant by market (Dollars per installed MW-year): 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2012	$201,658	$19,917	$0	$0	$0	$221,575

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 6-13 Net revenue for a wind installation by market[17] (Dollars per installed MW-year): 2012

	Energy	Credits	Capacity	Total
2012 (ComEd)	$67,294	$57,709	$2,435	$127,438
2012 (PENELEC)	$68,913	$58,450	$5,439	$132,802

17 Credits include a wind production tax credit and Renewable Energy Credits (RECs). See "Pricing" <http://paaeps.com/credit/pricing.do> (Accessed March 6, 2013) and "Public Notice of Winning Bidders and Average Prices" <http://www2.illinois.gov/ipa/Documents/Public-Notice-Ameren-ComEd-spring-2012-REC-Procurement-Results-2012-05-16.pdf> (Accessed March 6, 2013).

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 6-14 Net revenue for a solar installation by market[18] (Dollars per installed MW-year): 2012

	Energy	Credits	Capacity	Total
2012	$50,363	$314,530	$17,565	$382,458

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized fixed costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility over 20 years, at a constant nominal annual rate.

The extent to which net revenues cover the levelized fixed costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue.

Net revenue includes net revenue from the PJM Energy Market, from the PJM Capacity Market and from any applicable ancillary service plus production tax credits and RECs for wind installations and SRECs for solar installations.

Table 6-15 New entrant 20-year levelized fixed costs[19, 20] (By plant type (Dollars per installed MW-year)): 2009 through 2012

	20-Year Levelized Fixed Cost			
	2009	2010	2011	2012
Combustion Turbine	$128,705	$131,044	$110,589	$113,027
Combined Cycle	$173,174	$175,250	$153,682	$155,294
Coal Plant	$446,550	$465,455	$474,692	$480,662
Integrated Gasification Combined Cycle				$714,550
Nuclear Plant				$801,100
Wind Installation (with 1603 grant)				$196,186
Solar Installation (with 1603 grant)				$394,855

New Entrant Combustion Turbine

In 2012, a new CT would not have received sufficient net revenue to cover levelized fixed costs in any zone.

Table 6-16 Percent of 20-year levelized fixed costs recovered by CT energy and capacity net revenue (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012
AECO	55%	80%	87%	61%
AEP	31%	49%	64%	32%
AP	50%	74%	75%	36%
ATSI	NA	NA	NA	NA
BGE	70%	94%	89%	70%
ComEd	30%	47%	58%	29%
DAY	30%	49%	64%	34%
DEOK	NA	NA	NA	NA
DLCO	31%	53%	67%	34%
Dominion	40%	73%	80%	40%
DPL	56%	81%	85%	72%
JCPL	54%	79%	85%	60%
Met-Ed	50%	79%	82%	60%
PECO	53%	79%	86%	62%
PENELEC	47%	68%	74%	57%
Pepco	72%	93%	85%	66%
PPL	49%	75%	84%	58%
PSEG	53%	78%	79%	63%
RECO	NA	NA	NA	NA
PJM	45%	70%	77%	48%

Figure 6-2 compares zonal net revenue for a new entrant CT for 2009 through 2012 to the 2012 levelized fixed cost. Figure 6-3 shows zonal net revenue for the new entrant CT for 2009 through 2012 by LDA with the applicable annual levelized fixed cost.

18 Credits include Solar Renewable Energy Credits (SRECs). See "SREC Pricing Archive" <http://www.njcleanenergy.com/renewable-energy/project-activity-reports/srec-pricing/srec-pricing/archive> (Accessed March 6, 2013).

19 Levelized fixed costs provided by Pasteris Energy, Inc.

20 Under Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 the United States Department of the Treasury makes payments to owners who place in service specified energy property and apply for such payments. The purpose of the payment is to reimburse eligible applicants for a portion of the capital cost of such property. Solar and Wind energy properties are eligible for a 30 percent payment of the total eligible capital cost of the project. This 30 percent payment reduced the calculated fixed nominal levelized revenue requirements of the CONE Solar and Wind technologies.

Figure 6-2 New entrant CT net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2012

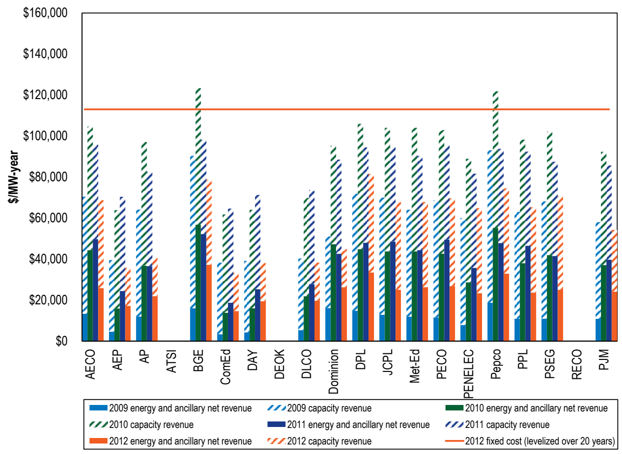


Figure 6-3 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2012

New Entrant Combined Cycle

In 2012, a new CC would have received net revenue sufficient to cover levelized fixed costs in three zones and sufficient to cover more than 90 percent of annual levelized fixed costs in nine of 16 relevant zones.

Table 6-17 Percent of 20-year levelized fixed costs recovered by CC energy and capacity net revenue: 2009 through 2012

Zone	2009	2010	2011	2012
AECO	72%	98%	115%	95%
AEP	40%	57%	86%	70%
AP	67%	89%	106%	78%
ATSI	NA	NA	NA	NA
BGE	87%	112%	117%	108%
ComEd	34%	49%	62%	53%
DAY	38%	56%	85%	74%
DEOK	NA	NA	NA	NA
DLCO	38%	59%	85%	71%
Dominion	62%	96%	107%	80%
DPL	73%	98%	113%	107%
JCPL	72%	97%	113%	94%
Met-Ed	65%	93%	105%	91%
PECO	69%	94%	111%	93%
PENELEC	61%	83%	103%	97%
Pepco	88%	110%	111%	103%
PPL	63%	87%	104%	88%
PSEG	69%	95%	107%	94%
RECO	NA	NA	NA	NA
PJM	60%	85%	101%	84%

Figure 6-4 compares zonal net revenue for a new entrant CC for 2009 through 2012 to the 2012 levelized fixed cost. Figure 6-5 shows zonal net revenue for the new entrant CC for 2009 through 2012 by LDA with the applicable yearly levelized fixed cost.

Figure 6-4 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2012

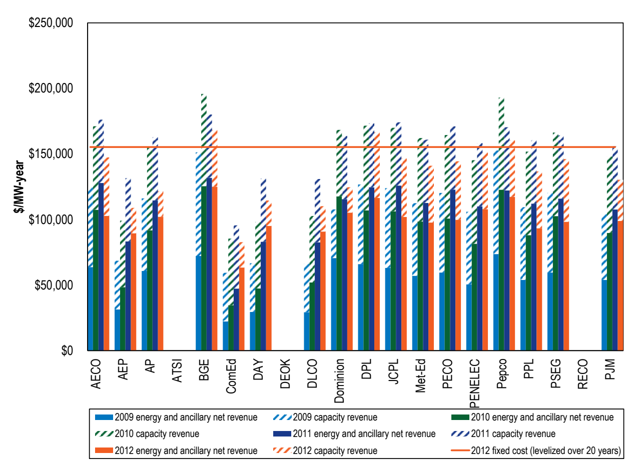


Figure 6-5 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2012

New Entrant Coal Plant

In 2012, a new CP would not have received sufficient net revenue to cover levelized fixed costs in any zone and would not have received sufficient net revenue to cover more than 20 percent of levelized fixed costs in any zone.

Table 6-18 Percent of 20-year levelized fixed costs recovered by CP energy and capacity net revenue: 2009 through 2012

Zone	2009	2010	2011	2012
AECO	33%	45%	25%	14%
AEP	13%	23%	25%	13%
AP	23%	34%	30%	15%
ATSI	NA	NA	NA	NA
BGE	28%	32%	22%	14%
ComEd	18%	33%	29%	15%
DAY	15%	27%	23%	13%
DEOK	NA	NA	NA	NA
DLCO	14%	27%	19%	13%
Dominion	19%	41%	26%	8%
DPL	22%	45%	30%	16%
JCPL	30%	45%	25%	15%
Met-Ed	25%	43%	23%	17%
PECO	31%	44%	25%	14%
PENELEC	30%	39%	30%	20%
Pepco	33%	49%	25%	14%
PPL	28%	38%	26%	12%
PSEG	52%	40%	20%	14%
RECO	NA	NA	NA	NA
PJM	25%	38%	25%	13%

Figure 6-6 compares zonal net revenue for a new entrant CP for 2009 through 2012 to the 2012 levelized fixed cost. Figure 6-7 shows zonal net revenue for the new entrant CP for 2009 through 2012 by LDA with the applicable yearly levelized fixed cost.

Figure 6-6 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2012

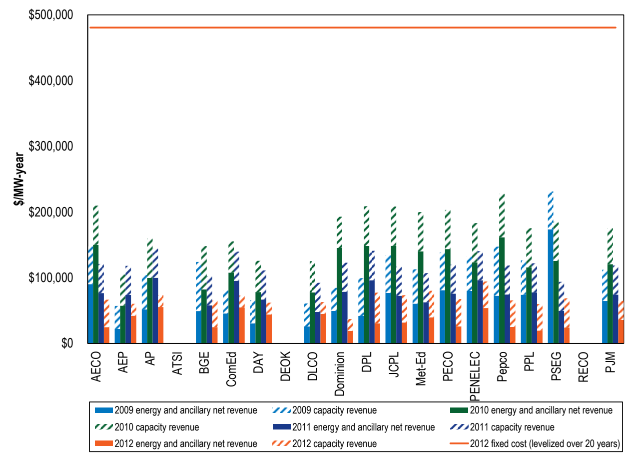
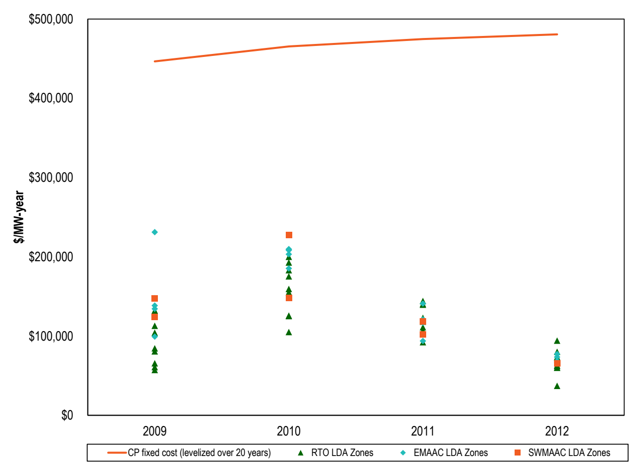


Figure 6-7 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2012



New Entrant Integrated Gasification Combined Cycle

In 2012, a new IGCC would not have received sufficient net revenue to cover levelized fixed costs.

Table 6-19 Percent of 20-year levelized fixed costs recovered by IGCC energy and capacity net revenue

Zone	2012
Dominion	5%

New Entrant Nuclear Plant

In 2012, a new nuclear plant would not have received sufficient net revenue to cover levelized fixed costs.

Table 6-20 Percent of 20-year levelized fixed costs recovered by nuclear energy and capacity net revenue

Zone	2012
AEP	28%

New Entrant Wind Installation

In 2012, a new wind installation would not have received sufficient net revenue to cover levelized fixed costs.

Table 6-21 Percent of 20-year levelized fixed costs recovered by wind energy and capacity net revenue and wind credits

Zone	2012
ComEd	65%
PENELEC	68%

New Entrant Solar Installation

In 2012, a new solar installation would have received sufficient net revenue to cover 97 percent of levelized fixed costs.

Table 6-22 Percent of 20-year levelized fixed costs recovered by solar energy and capacity net revenue and solar credits

Zone	2012
PSEG	97%

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2012, the yearly average operating cost of the CC was lower than the average operating costs of the CP, driven by the relative cost of gas versus coal although that relationship reversed toward the end of the year.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy cost units and therefore tend to be marginal in the energy market, when load requires them, and set prices in the energy market, when they run. When this occurs, CT energy market net revenues are small 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. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market.

However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which is generally an inaccurate estimate of actual net revenues in the current operating year and an inaccurate estimate of expected net revenues for the forward capacity market. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2012, zonal energy net revenues decreased for most CCs and all CTs, while capacity market prices decreased in all but DPL and PSEG. As a result, there were three zones that, when both energy revenues and capacity revenues are considered, showed revenue adequacy for a new entrant CC in 2012.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. However, when less efficient coal units are on the margin net revenues are higher for more efficient coal units.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 6-15 The results are shown in Table 6-23.[21]

Table 6-23 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$120,527	13.8%	$165,294	13.7%	$510,662	13.6%
Base Case	$113,027	12.0%	$155,294	12.0%	$480,662	12.0%
Sensitivity 2	$105,527	10.2%	$145,294	10.2%	$450,662	10.3%
Sensitivity 3	$98,027	8.2%	$135,294	8.4%	$420,662	8.5%
Sensitivity 4	$90,527	6.1%	$125,294	6.5%	$390,662	6.7%
Sensitivity 5	$83,027	3.8%	$115,294	4.4%	$360,662	4.7%
Sensitivity 6	$75,527	0.9%	$105,294	2.1%	$330,662	2.5%

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 6-24 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls. Table 6-25 shows the levelized annual revenue requirements associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

Table 6-24 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percentage of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$120,273	$164,751
Sensitivity 2	55%	$116,650	$160,023
Base Case	50%	$113,027	$155,294
Sensitivity 3	45%	$109,405	$150,566
Sensitivity 4	40%	$105,783	$145,837
Sensitivity 5	35%	$102,160	$141,110
Sensitivity 6	30%	$98,536	$136,381

Table 6-25 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$101,686	$140,493
Sensitivity 2	25	$105,973	$146,087
Base Case	20	$113,027	$155,294
Sensitivity 3	15	$118,955	$163,030
Sensitivity 4	10	$126,814	$173,287

Table 6-26 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

21 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

Table 6-26 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0.0%	$109,587	$0	0.0%	$151,576
Sensitivity 2	$4,904	1.5%	$111,307	$7,841	1.2%	$153,435
Base Case	$9,809	3.1%	$113,027	$15,682	2.4%	$155,294
Sensitivity 3	$14,714	4.6%	$114,747	$23,523	3.5%	$157,153
Sensitivity 4	$19,618	6.1%	$116,466	$31,364	4.7%	$159,012
Sensitivity 5	$24,522	7.7%	$118,186	$39,205	5.9%	$160,871
Sensitivity 6	$29,427	9.2%	$119,906	$47,046	7.1%	$162,730
Sensitivity 7	$50,000	15.7%	$127,120	$50,000	7.5%	$163,430
Sensitivity 8	$75,000	23.5%	$135,886	$75,000	11.3%	$169,357
Sensitivity 9	$100,000	31.3%	$144,652	$100,000	15.0%	$175,284

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs in this analysis, the actual avoidable costs are adjusted to exclude APIR. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. APIR may also reflect investments in environmental technology which were made in prior years to keep units in service and thus it would not be appropriate to include them in this analysis of the incentives to continue to operate units.

The MMU calculated unit specific energy and ancillary service net revenues for several technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM Energy and Ancillary Service Markets alone provide sufficient incentive for continued operations in PJM Markets. Energy and Ancillary Service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include Day-Ahead and balancing energy revenues, less submitted or estimated operating costs, as well as any applicable Day-Ahead or Balancing Operating Reserve Credits. Ancillary service revenues include actual unit credits for regulation services, spinning reserves and black start capability, in addition to actual or class average reactive revenues determined by actual FERC filings.

The MMU calculated average avoidable costs in dollars per MW-year based on actual submitted Avoidable Cost Rate (ACR) data for units associated with the most recent 2011/2012 and 2012/2013 RPM Auctions.[22] For units that did not submit ACR data, the default ACR was used.

The RPM capacity market design provides supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2011/2012

22 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the Base Residual Auction.

and 2012/2013 delivery years, reflecting commitments made in Base Residual Auctions (BRA) and subsequent Incremental Auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM Markets in 2012. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[23] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied.

These quartiles remain constant throughout the analysis and are used to present the range of data while avoiding the influence of outliers. The three break points between the four quartiles are presented. Table 6-28 shows average energy and ancillary service net revenues by quartile for select technology classes.

Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivery costs associated with input fuels. The average net revenues for diesel units, the oil or gas-fired steam technology, and several of the older CT technologies reflect both units burning natural gas and units burning oil distillates. The geographical distribution of units for a given technology class across the PJM footprint determines individual unit price levels and thus significantly affects average energy net revenue for that technology class.

Table 6-27 Class average net revenue from energy and ancillary markets and associated recovery of class average avoidable costs and total revenue from all markets and associated recovery of class average avoidable costs: 2012

Technology	Total Installed Capacity (ICAP)	Class average energy and ancillary net revenue ($/MW-year)	Class average energy net revenue and capacity revenue ($/MW-year)	Class average avoidable costs ($/MW-year)
CC - NUG Cogeneration Frame B or E Technology	2,148	$18,722	$56,929	$44,714
CC - Two of Three on One Frame F Technology	13,353	$105,327	$133,370	$17,579
CT - First & Second Generation Aero (P&W FT 4)	3,219	$2,493	$43,763	$8,199
CT - First & Second Generation Frame B	3,759	($995)	$35,116	$9,595
CT - Second Generation Frame E	9,380	$23,083	$52,237	$8,519
CT - Third Generation Aero	3,325	$20,490	$53,194	$19,554
CT - Third Generation Frame F	7,646	$31,634	$55,734	$8,493
Diesel	496	$4,308	$39,606	$10,752
Hydro	1,995	$164,428	$196,127	$27,432
Nuclear	29,840	$172,750	$202,050	NA
Oil or Gas Steam	9,632	$14,743	$47,814	$27,009
Pumped Storage	4,952	$21,243	$61,676	$11,334
Sub-Critical Coal	31,433	$21,697	$45,368	$57,850
Super Critical Coal	23,454	$48,010	$69,035	$57,978

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM. The underlying analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Table 6-27 provides a summary of results by technology class, as well as the total installed capacity associated with each technology analyzed.

The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 6-27 represent a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile. Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year.

23 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

Table 6-28 Energy and ancillary service net revenue by quartile for select technologies for 2012

	Energy and ancillary net revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$3,074	$35,327	$68,031
CC - Two of Three on One Frame F Technology	$20,329	$85,223	$126,132
CT - First & Second Generation Aero (P&W FT 4)	($1,259)	($336)	$5,135
CT - First & Second Generation Frame B	($4,467)	($1,195)	$451
CT - Second Generation Frame E	$1,385	$13,092	$28,711
CT - Third Generation Aero	$9,383	$26,680	$39,202
CT - Third Generation Frame F	$8,775	$29,801	$71,987
Diesel	($6,964)	($1)	$921
Hydro	$65,957	$128,200	$220,117
Nuclear	$142,688	$189,534	$207,802
Oil or Gas Steam	($1,559)	$85	$9,393
Pumped Storage	$10,510	$21,160	$29,131
Sub-Critical Coal	$1,100	$12,556	$40,312
Super Critical Coal	$32,515	$50,425	$65,786

Table 6-29 Capacity revenue by quartile for select technologies for 2012[24]

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$29,893	$42,994	$45,494
CC - Two of Three on One Frame F Technology	$19,407	$20,162	$43,059
CT - First & Second Generation Aero (P&W FT 4)	$39,749	$43,869	$46,169
CT - First & Second Generation Frame B	$19,464	$38,952	$44,122
CT - Second Generation Frame E	$19,264	$20,560	$45,061
CT - Third Generation Aero	$18,813	$20,081	$45,806
CT - Third Generation Frame F	$18,175	$19,428	$21,469
Diesel	$18,210	$20,187	$64,292
Hydro	$18,134	$38,698	$45,261
Nuclear	$20,013	$20,313	$44,808
Oil or Gas Steam	$17,332	$40,702	$45,497
Pumped Storage	$43,188	$45,216	$46,012
Sub-Critical Coal	$17,634	$19,468	$41,415
Super Critical Coal	$4	$18,622	$42,173

Table 6-30 Combined revenue from all markets by quartile for select technologies for 2012

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$32,966	$78,322	$113,525
CC - Two of Three on One Frame F Technology	$39,737	$105,385	$169,191
CT - First & Second Generation Aero (P&W FT 4)	$38,490	$43,533	$51,304
CT - First & Second Generation Frame B	$14,997	$37,757	$44,573
CT - Second Generation Frame E	$20,648	$33,652	$73,772
CT - Third Generation Aero	$28,197	$46,760	$85,007
CT - Third Generation Frame F	$26,949	$49,230	$93,456
Diesel	$11,246	$20,187	$65,213
Hydro	$84,090	$166,898	$265,378
Nuclear	$162,700	$209,847	$252,610
Oil or Gas Steam	$15,773	$40,787	$54,889
Pumped Storage	$53,698	$66,377	$75,143
Sub-Critical Coal	$18,733	$32,023	$81,727
Super Critical Coal	$32,518	$69,047	$107,959

24 A number of coal units did not clear the relevant RPM auctions and received no capacity revenue.

Table 6-31 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2012, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone.

Table 6-32 shows the avoidable cost recovery from all PJM markets by quartiles.

Table 6-33 and Table 6-34 show the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets for 2009, 2010, 2011 and 2012. Since 2009, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units in PJM, with the exception of coal and oil or gas steam units.

Table 6-31 Avoidable cost recovery by quartile from energy and ancillary net revenue for select technologies for 2012

	Recovery of avoidable costs from energy and ancillary net revenue		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	54%	134%	262%
CC - Two of Three on One Frame F Technology	156%	381%	612%
CT - First & Second Generation Aero (P&W FT 4)	(17%)	(2%)	58%
CT - First & Second Generation Frame B	(48%)	(24%)	11%
CT - Second Generation Frame E	77%	133%	211%
CT - Third Generation Aero	94%	164%	187%
CT - Third Generation Frame F	138%	337%	540%
Diesel	(34%)	(10%)	51%
Hydro	472%	741%	1,061%
Nuclear	NA	NA	NA
Oil or Gas Steam	(17%)	0%	33%
Pumped Storage	0%	342%	577%
Sub-Critical Coal	0%	12%	65%
Super Critical Coal	41%	72%	100%

Table 6-32 Avoidable cost recovery by quartile from all PJM Markets for select technologies for 2012

	Recovery of avoidable costs from all markets		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	151%	220%	339%
CC - Two of Three on One Frame F Technology	329%	551%	723%
CT - First & Second Generation Aero (P&W FT 4)	438%	497%	1,015%
CT - First & Second Generation Frame B	215%	373%	494%
CT - Second Generation Frame E	284%	415%	618%
CT - Third Generation Aero	205%	269%	368%
CT - Third Generation Frame F	418%	742%	1,010%
Diesel	102%	169%	471%
Hydro	634%	897%	1,199%
Nuclear	NA	NA	NA
Oil or Gas Steam	53%	143%	179%
Pumped Storage	162%	1,119%	1,154%
Sub-Critical Coal	28%	66%	111%
Super Critical Coal	89%	126%	154%

Table 6-33 Proportion of units recovering avoidable costs from energy and ancillary markets for 2009 to 2012

	Units with full recovery from energy and ancillary services markets			
Technology	2009	2010	2011	2012
CC - NUG Cogeneration Frame B or E Technology	39%	71%	61%	67%
CC - Two of Three on One Frame F Technology	63%	76%	90%	86%
CT - First & Second Generation Aero (P&W FT 4)	8%	5%	7%	6%
CT - First & Second Generation Frame B	3%	11%	19%	18%
CT - Second Generation Frame E	21%	48%	63%	73%
CT - Third Generation Aero	17%	36%	72%	68%
CT - Third Generation Frame F	18%	39%	59%	77%
Diesel	64%	59%	56%	44%
Hydro	100%	100%	96%	100%
Nuclear	100%	100%	100%	100%
Oil or Gas Steam	28%	42%	43%	36%
Pumped Storage	70%	90%	70%	90%
Sub-Critical Coal	76%	82%	70%	50%
Super Critical Coal	86%	94%	92%	61%

Table 6-34 Proportion of units recovering avoidable costs from all markets for 2009 to 2012

	Units with full recovery from all markets			
Technology	2009	2010	2011	2012
CC - NUG Cogeneration Frame B or E Technology	87%	88%	89%	79%
CC - Two of Three on One Frame F Technology	92%	100%	100%	97%
CT - First & Second Generation Aero (P&W FT 4)	99%	99%	100%	100%
CT - First & Second Generation Frame B	99%	98%	92%	90%
CT - Second Generation Frame E	100%	100%	100%	100%
CT - Third Generation Aero	99%	99%	99%	94%
CT - Third Generation Frame F	95%	96%	98%	96%
Diesel	95%	97%	91%	85%
Hydro	100%	100%	100%	100%
Nuclear	100%	100%	100%	100%
Oil or Gas Steam	93%	88%	88%	73%
Pumped Storage	100%	100%	100%	100%
Sub-Critical Coal	88%	93%	87%	61%
Super Critical Coal	97%	100%	96%	85%

At-Risk Coal Plants

A number of sub-critical and supercritical coal units did not recover avoidable costs from total market revenues, including capacity market revenues. These units are considered at risk of retirement.

Units that have either already started the deactivation process or are expected to request deactivation are excluded from the at-risk analysis.[25]

Energy market net revenues are a function of energy prices and operating costs. Avoidable costs are a function of technology, unit size and age of units and, in some cases, unit specific investments needed to maintain or enhance reliability or to comply with environmental regulations.

Table 6-35 compares characteristics of the subset of coal units with less than 100 percent recovery of avoidable costs after capacity revenues, to characteristics of coal plants with greater than or equal to 100 percent recovery. Units that did not cover their avoidable costs were, on average, less efficient, ran less often and had substantially higher avoidable costs.

Units that did not cover avoidable costs generally sold capacity in RPM auctions, but some showed reduced capacity market revenues which may be attributable to partial clearing in Base Residual Auctions (BRA), high outage rates affecting the unforced capacity level that can be offered, or performance penalties associated with nonperformance. Units that did not cover avoidable costs tended to have higher avoidable costs. It is possible that these units cleared in the capacity market at a level below avoidable cost recovery due to the lag in market revenues used to calculate offer caps associated

25 This is based in part on information provided to PJM at its request by generation owners indicating their plans for retirements, retrofits, and related retrofits outage schedules to the extent they were known and understood by generation owners following the issuance of the final MATS rule.

with each delivery year which led to an offer cap that understated the annual recovery needed from the RPM, or, these units may have been offered at a price below the avoidable cost based offer cap.

Table 6-35 Profile of coal units

	Coal plants with less than full recovery of avoidable costs	Coal plants with full recovery of avoidable costs
Total Installed Capacity (ICAP)	3,724	35,012
Avg. Installed Capacity (ICAP)	248	347
Avg. Age of Plant (Years)	46	36
Avg. Heat Rate (Btu/kWh)	10,999	10,564
Avg. Run Hours (Hours)	3,348	6,054
Avg. Avoidable Costs ($/MW-year)	167	149

In 2012, 15 coal units did not cover their avoidable costs. The risk of deactivation for these units depends on the degree to which revenues from all markets are less than avoidable costs. Table 6-36 shows the installed capacity (MW) associated with levels of recovery for coal plants.

Table 6-36 Installed capacity associated with levels of avoidable cost recovery: 2012

Groups of coal plants by percent recovery of avoidable cost	Installed capacity (MW)	Percent of total
0% - 65%	1,110	3%
65% - 75%	555	1%
75% - 90%	531	1%
90% - 100%	1,528	4%
> 100%	35,012	90%
Total	38,737	100%

Environmental Rules

Environmental rules may affect decisions about investments in existing units, investment in new units and decisions to retire units. These capital expenditures, if required, would significantly impact the profitability of coal plants lacking sufficient environmental controls. Coal plants facing capital expenditures may be retired if it is not expected that the plants will recover the associated costs through a combination of energy or capacity revenue. The extent to which capital expenditures affect an individual unit's offer in the capacity market depends upon the size of the unit, the level of investment required, the life and recovery rate of the investment, avoidable costs, and the expected net revenue.Units lacking MATS compliant controls for NO_x emissions, SO_2 emissions, particulates, or all three, were identified as units potentially facing significant capital expenditures on environmental control technologies. Table 6-37 shows the number of units and associated installed capacity lacking MATS compliant environmental controls.

Table 6-37 Coal plants lacking MATS compliant environmental controls

	Coal plants without NO_x controls	Coal plants without SO_2 controls	Coal plants without particulate controls	Coal plants lacking NO_x, SO_2, and particulate controls
Number of units	49	22	33	11
Installed capacity (ICAP)	10,444	5,089	11,394	1,722

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 Cross-State Air Pollution Rule (CSAPR), would if implemented, potentially 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. 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 some 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 had a significant impact 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. The rule establishes a compliance deadline of April 16, 2015. A source may obtain an extension for up to one additional year where necessary for the installation of controls. The CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing five sources for source categories with less than 30 sources).

  The MATS rule affected offers in the 2015/2016 RPM Base Residual Auction, held in May 2012.

  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.

- **Cross-State Air Pollution Rule.** 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.[3] EPA has filed a petition for rehearing. While a decision on rehearing is pending, 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).[4] 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. The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs), and particulate matter. 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 March 27, 2012, the EPA proposed a Carbon Pollution Standard for new fossil-fired electric utility generating units. The

1 For quantification of the impact on new entrant wind and solar installations, see the *2012 State of the Market Report for PJM*, 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 See EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

4 *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 (January 14, 2013).

proposed standard would limit emissions from new electric generating units to 1,000 pounds of CO_2 per MWh. In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the GHG rule, rejecting challenges brought by industry groups and a number of states.[5]

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. New Jersey's HEDD rule,[6] 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.[7] New Jersey's HEDD rule is implemented in two phases. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports and are subject to various behavioral requirements. After May 1, 2015, new, reconstructed or modified turbines must comply with certain technology standards. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan, describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_X emission rates.

  The HEDD rule affected offers in the 2015/2016 RPM Base Residual Auction, held in May 2012.

- **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 2012 for the 2012-2014 compliance period were $1.93 per ton throughout the year, the price floor for 2012.

5 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
6 N.J.A.C. § 7:27-19.
7 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. At the end of 2012, 68.2 percent of coal steam MW's 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. NO_x emission controlling technology is used by nearly all fossil fuel unit types, and 90.9 percent of fossil fuel fired capacity in PJM has 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 2012, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from a requirement that renewables serve 1.5 percent of all load served in Ohio, to 9.21 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards.

Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy which is greater than the marginal cost of producing energy. 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 negative LMP is equal to the marginal cost of producing minus the credit received for each MWh. 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.[8,9] In recent years, the EPA has been actively defining its standards and considering potential mechanisms, such as cap and trade, to facilitate meeting those standards. EPA actions have and are expected to continue to affect the cost to build and operate generating units in PJM which in turn affect 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 CAA affects generating plants that rely on draw water from jurisdictional water bodies.

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.

The CAA requires the standards to reflect the maximum degree of reduction in hazardous air pollutant emissions that is achievable taking into consideration the cost of achieving the emissions reductions, any non air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the Maximum Achievable Control Technology (MACT). The MACT floor is the minimum control level allowed for NESHAP and ensures that all major hazardous air pollutant emission sources achieve the level of control already achieved by the better-controlled and lower-emitting sources in each category. Section 112 of the CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing 5 sources for source categories with less than 30 sources).

On December 16, 2011, the EPA signed its Mercury and Air Toxics Standards rule (MATS) rule, promulgated pursuant to CAA § 112, and its Utility New Source Performance Standards (NSPS), promulgated pursuant to CAA § 111.[10]

The MATS rule applies the MACT to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide. The rule establishes a compliance deadline of April 16, 2015, near the end of the 2014/2015 RPM Delivery Year.[11] A source may obtain an extension for up to one additional year where necessary for the installation of controls.

The MATS rule sets emissions limits separately for each pollutant. Only filterable particulate matter (PM), rather than both filterable and condensable PM, is considered for compliance with emissions limits. Work practice standards are included for startup and shutdown periods. The rule extends the period of averaging for Hg from 30 to 90 days, but tightens the applicable standards for sources using averaging. The rule requires either

8 42 U.S.C. § 7401 et seq. (2000),

9 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.

10 *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 Nos. EPA-HQ-OAR-2009-0234 (MATS) & EPA-HQ-OAR-2011-0044 (Utility NSPS), 77 Fed. Reg. 9304 (February 16, 2012).

11 *Id.* at 9465.

continuous monitoring or periodic quarterly testing to demonstrate continuous compliance. The revised rule establishes seven categories of covered units.

The Utility NSPS rule requires new coal- and oil-fired electric utility steam generating units constructed after May 3, 2012, to comply with amended emission standards for SO_2, NO_X and filterable PM.

On November 16, 2012, EPA proposed to change the startup and shutdown provisions related to the PM standard and definitional and monitoring provisions in the Utility NSPS under MATS.[12] MATS rules for existing units were unaffected.

Control of NO_x and SO_2 Emissions Allowances

The CAA requires States 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.[13] The EPA has sought to promulgate default Federal rules to achieve this objective.

The CAA requires EPA to review and, if appropriate, revise the air quality criteria for the primary (health-based) and secondary (welfare-based) NAAQs every five years. The NAAQS are the targets to which compliance mechanisms such as the rules regulating transport are directed. A final rule on SO_2 primary NAAQS was published June 22, 2010.[14] A final rule for secondary NAAQS for NO_x and SO_x became effective June 4, 2012.[15] A proposed rule for primary and secondary NAAQS for Ozone (O_3) is expected in May 2013.[16] On February 17, 2013, EPA sent letters to state governments outlining the areas it is considering designating as nonattainment for the 2010 primary standard for sulfur dioxide. Some of these areas are in PJM states, including Pennsylvania, Ohio, Kentucky, Tennessee, Indiana and Illinois. Designation of a nonattainment area in the PJM region could impact the attainment status of generating units within PJM, and require investment in additional controls for SO_2.

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.[17] EPA has filed a petition for rehearing. While a decision on rehearing is pending, the EPA continues to process under CAIR a number of pending requests, including State Implementation Plans (SIPs), that were 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).[18] 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").[19]

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.[20] The proposed rule allowed owners and operators of emergency stationary internal

12 *Reconsideration of Certain New Source and Startup/Shutdown 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 Nos. EPA-HQ-OAR-2009-0234 (MATS) & EPA-HQ-OAR-2011-0044 (Utility NSPS), 77 Fed. Reg. 71323, 71325 (November 30, 2012).

13 CAA § 110(a)(2)(D)(i)(I).

14 See 40 CFR Parts 50, 53, and 58.

15 *Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Sulfur*, 77 Fed. Reg. 20218 (April 3, 2012).

16 See EPA Docket No. EPA-HQ-OAR-2008-0699.

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

18 *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 (January 14, 2013) ("Final NESHAP RICE Rule").

19 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.

20 *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.

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.[21] The final rule approves the proposed 100 hours per year exception, provided that RICE uses ultra low sulfur diesel fuel (ULSD).[22] Otherwise a 15-hour exception applies.[23] 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.[24] 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.[25] 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.[26]

The EPA determined that in order to regulate greenhouse gas emissions, it would need to develop a different standard for determining major sources that require permits to emit greenhouse gases than the standards applied to other pollutants.[27] Application of the 100 or 250 tons per year (tpy) maximum annual emissions rate standards applied to other types of pollutants would have been so low compared to actual emissions as to impede the ability to construct or modify regulated facilities.[28]

On May 13, 2010, the EPA issued a rule addressing greenhouse gases (GHG) from the largest stationary sources, including power plants.[29] The Prevention of Significant Deterioration and Title V programs under the CAA impose certain permitting requirements on sources of pollutants. The EPA began phased implementation of this rule on January 2, 2011, referring to each phase as a step. In step 1, the EPA required affected facilities to include GHGs in their permit if they increase net GHG emissions by at least 75,000 tpy CO_2 equivalent and also significantly increase emissions of at least one non-GHG pollutant.[30] The U.S. Court of Appeals for the D.C. Circuit also upheld the Tailoring Rule in its June 26th decision.[31]

On December 23, 2010, the EPA entered a settlement agreement to resolve the requests by States and other litigants for performance standards and emission guidelines for GHG emissions for new and significantly modified sources, as provided under Sections 111(b) and (d) of the CAA. A proposed rule is expected to amend the standards of performance for electric utility steam generating units codified in EPA regulations to address regulation of GHG.

On July 1, 2011, the GHG Tailoring Rule was expanded under step 2 to cover all new facilities with GHG emissions of at least 100,000 tpy and modifications at existing facilities that would increase GHG emissions by at least 75,000 tpy.[32] These permits must demonstrate the use of best available control technology (BACT) to minimize GHG emission increases when facilities are constructed or significantly modified.[33]

Effective August 13, 2012, the EPA implemented step 3.[34] Step 3 leaves the step 2 thresholds unchanged. Step 3 allows permitting on a plant wide basis so that changes at a facility that do not violate the plant wide limits do not require additional permitting.[35]

21 *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).
22 Final NESHAP RICE Rule at 31–24.
23 *Id.* at 31.
24 Massachusetts v. EPA, 549 U.S. 497.
25 *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).
26 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
27 EPA, Final Rule, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, Docket No. EPA-HQ-OAR-2009-0517, 75 Fed. Reg. 31514 (June 3, 2010) ("GHG Tailoring Rule").
28 *Id.* at 31516.
29 *Id.*.
30 *Id.* at 31516.
31 Coalition for Responsible Regulation, Inc., et al. v. EPA.
32 *Id.*
33 *Id.* at 31520.
34 EPA, Final Rule, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3, GHG Plantwide Applicability Limitations and GHG Synthetic Minor Limitations*, Docket No. EPA-HQ-2009-0517, 77 Fed Reg 41051 (July 12, 2012).
35 *Id.* at 41055.

On March 27, 2012, the EPA proposed an emissions standard for CO_2 from new fossil-fired electric utility generating units.[36] The proposed standard limits emissions from new units to 1,000 pounds of CO_2 per MWh. The rule excludes units currently in service or that have acquired full preconstruction permits prior to issuance of the proposal and that commence construction during the next 12 months. New units covered by the rule include only certain types of units that meet certain sales thresholds. Covered unit types include fossil fuel fired steam and combined cycle (CC) units, but exclude stationary simple cycle combustion turbine units. Covered units include only units that supply to the grid "more than one-third of [the unit's] potential annual electric output and more than 25 MW net-electrical output (MWe)."[37] EPA states that new natural gas CC units should be able to meet the proposed standard without add on controls, based in part on data showing that nearly 95 percent of the natural gas CC units built between 2006 and 2010 would meet the standard. EPA states that new coal or petroleum coke units that incorporate technology to reduce carbon dioxide emissions, such as carbon capture and storage (CCS), could meet the standard.[38] New units that use CCS would have the option under the proposed rule to show twelve-month compliance with reference to a level calculated to consider an estimated 30 year average of CO_2 emissions, the year in which CCS would be installed, and the "best demonstrated performance of a coal-fired facility without CCS."[39]

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 Clean Water Act (CWA).[40] A settlement in a Federal Court, as modified, obligates the EPA to issue a final rule no later than June 27, 2013.[41]

This rule seeks to protect aquatic life from being trapped on the screens that cover water intake structures over the cooling system at a generating facility (impingement) or drawn into the cooling system (entrainment).

The EPA would study facilities that draw 125 MGD or more of water to evaluate, in a process open to the public, the need for site specific controls to prevent entrainment, and, if there is such a need, the EPA would determine those controls.

The rule would require new or upgraded units to include or add technology equivalent to closed cycle cooling.

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. New Jersey's HEDD rule,[42] 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.[43]

New Jersey's HEDD rule will be implemented in two phases. For the first phase, owners/operators of HEDD units have prepared a 2009 HEDD Emission Reduction Compliance Demonstration Protocol (HEDD Protocol)

36 Standards for Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, EPA Docket No. EPA-HQ-OAR-2011-0660, 77 Fed. Reg. 22392 (April 13, 2012).

37 *Id.* at

38 *Id.* at 22392. EPA observes that PJM State Illinois, currently requires CCS for new coal generation.

39 *Id.* at 22406.

40 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).

41 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.

42 N.J.A.C. § 7:27-19.

43 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).

and obtained the approval of the New Jersey Department of Environmental Protection. A HEDD Protocol may include: installation of emissions controls at the HEDD unit or a non-HEDD unit; run-time limitations; commitment to use natural gas on HEDD units if dual fueled; implementation of energy efficiency, demand response or renewable energy measures; or other approved measures. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports. The second phase involves performance standards applicable after May 1, 2015. New, reconstructed or modified turbines must comply with State of the Art (SOTA), Lowest Achievable Emissions Rate (LAER) and Best Available Control Technology (BACT) standards, as applicable. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_x emission rates. On February 8, 2012, the Governor of New Jersey announced that no extension beyond the 2015 deadline would be granted.[44]

Table 7-1 shows the HEDD emissions limits applicable to each unit type.

Table 7-1 HEDD maximum NO_x emission rates[45]

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)[46] 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.[47]

Under RGGI, each state has its own CO_2 Budget Trading Program implemented through state regulations based on a common set of rules that allow the nine individual state programs to function as a single regional compliance market for CO_2 allowances. Starting in 2009, the RGGI rules require that qualifying power generators hold allowances sufficient to cover their total CO_2 emissions over each three year compliance period. Qualifying power generators can purchase their allowances for the compliance period directly from the quarterly auctions held before and during the compliance period, or from holders of allowances from previous auctions. Additional allowances can be made available via RGGI state approved qualifying offset projects, although offset allowances can make up only a limited portion of a regulated power plant's compliance obligation. The current maximum allowable contribution of CO_2 offset allowances to a power generation facility's compliance obligation is 3.3 percent of emissions per compliance period. The cap on the contribution of CO_2 offset allowances can be raised to 5 percent or to 10 percent if the calendar year average price of CO_2 allowances exceeds annual Consumer Price Index (CPI) adjusted stage 1 ($7) or stage 2 ($10) trigger prices, respectively.

A total of 14 auctions were held for 2009–2011 compliance period allowances, and 16 auctions have been held for 2012–2014 compliance period allowances.

Table 7-2 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions and additional 16 auctions held only for the 2012-2014 compliance period held as of December 31, 2012. Prices for auctions held in 2012 for the 2012-2014 compliance period were $1.93 per allowance (equal to one ton of CO_2), which is the current price floor for RGGI auctions. The average 2012 spot price for a 2012-2014 compliance period allowance was $1.96 per ton. Monthly average spot prices for the 2012-2014 compliance period ranged from $2.00 per ton in February to $1.94 per ton in July through November.

44 State of New Jersey, Press Release, "Governor Christie Continues Commitment to Clean Air with Aggressive Deadline for Power Plants to Reduce Emissions."

45 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.

46 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>.

47 A similar regional initiative has organized under the Western Climate Initiative, Inc. (WCI). The first mover is the California Air Resources Board (ARB), which has organized a cap and trade program that was implemented in 2012. That program will be coordinated with other U.S. states and Canadian provinces participating in WCI. One such participant, Quebec, adopted cap and trade rules on December 15, 2011. British Columbia, Manitoba and Ontario are also expected to coordinate cap and trade policies through WCI.

Figure 7-1 shows average, daily settled prices for NO_x and SO_2 emissions within PJM. In 2012, NO_x prices were 75.6 percent lower than in 2011. SO_2 prices were 57.6 percent lower in 2012 than in 2011. Figure 7-1 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.

Figure 7-1 Spot monthly average emission price comparison: 2011 and 2012

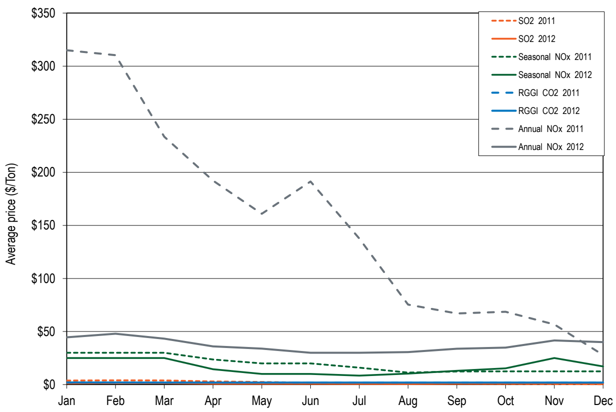


Table 7-2 RGGI CO_2 allowance auction prices and quantities (tons): 2009-2011 and 2012-2014 Compliance Periods[48]

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

48 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed January 21, 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 December 31, 2012, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 1.50 percent of all load served in Ohio, to 9.21 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2021. As shown in Table 7-3, New Jersey will require 22.5 percent of load to be served by renewable resources in 2022, 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 requires only 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 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 each per MWh from generation from "alternative energy resources" such as waste coal or pumped-storage hydroelectric, but allows two credits each per MWh of electricity generated by "renewable energy resources," which includes resources such as 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.

Table 7-3 Renewable standards of PJM jurisdictions to 2022[49,50]

Jurisdiction	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Delaware	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%
Illinois	8.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%
Indiana		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%	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	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%	22.50%
North Carolina	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%
Ohio	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%
Pennsylvania	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%
Washington, D.C.	7.50%	9.00%	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%
West Virginia				10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%	15.00%

Table 7-4 Solar renewable standards of PJM jurisdictions to 2022

Jurisdiction	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Delaware	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%
Illinois	0.00%	0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.10%	0.25%	0.35%	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%
Michigan	No Solar Standard										
New Jersey	0.39%	0.75%	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%
North Carolina	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%
Pennsylvania	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.50%	0.50%	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%
West Virginia	No Solar Standard										

Many PJM jurisdictions have also added requirements for the purchase of specific renewable resource technologies, specifically solar resources. These solar requirements are included in the standards shown in Table 7-3 but must be met by solar RECs (SRECs) only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have a requirement for the proportion of load served by solar units by 2022.[51] Indiana, Michigan, Virginia, and West Virginia have no specific solar standard. In 2012, the most stringent standard in PJM was Delaware's, requiring 0.40 percent of load to be served by solar resources. As Table 7-4 shows, by 2022, the most stringent standard will be New Jersey's which requires at least 3.56 percent of load to be served by solar.

49 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

50 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.

51 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the jurisdiction's solar requirement.

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 7-5 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind farms, starting at 4.50 percent in 2012 and escalating to 14.25 percent in 2022. Maryland, New Jersey, Pennsylvania[52], 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. North Carolina also requires a certain amount of power generated using swine waste and poultry waste to fulfill their renewable portfolio standards, while New Jersey requires 2,928 GWh of solar generation by 2022 (Table 7-5).

Table 7-6 Renewable alternative compliance payments in PJM jurisdictions: 2012

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	Voluntary standard		
Illinois	$2.16		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$658.00
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		

Table 7-5 Additional renewable standards of PJM jurisdictions to 2021

Jurisdiction		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Illinois	Wind Requirement	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	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%	0.00%
New Jersey	Solar Carve-Out (in GWh)	442	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518	2,928
North Carolina	Swine Waste	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	170	700	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%

PJM jurisdictions include various methods to comply 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 $658 per MWh.[53] 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 renewable portfolio standard be met through alternative compliance payments. Table 7-6 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 7-7 shows generation by jurisdiction and renewable resource type in 2012. 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 12,633.6 GWh of 42,531.6 Tier I GWh, or 59.6 percent, in the PJM footprint. As shown in Table 7-7, 42,531.6 GWh were generated by resources that were primarily renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 49.8 percent.

52 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.

53 See "New Jersey Renewables Portfolio Standard" <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0> (Accessed March 7, 2013).

Table 7-7 Renewable generation by jurisdiction and renewable resource type (GWh): 2012

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	61.4	0.0	0.0	0.0	0.0	0.0	0.0	61.4	122.8
Illinois	142.8	0.0	0.0	0.0	0.0	0.0	5,282.4	5,425.2	5,425.2
Indiana	0.0	0.0	34.7	0.0	0.0	0.0	2,638.6	2,673.3	2,673.3
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	93.9	0.0	1,653.5	10.8	604.8	0.0	299.3	2,057.5	2,662.3
Michigan	28.8	0.0	52.7	0.0	0.0	0.0	0.0	81.5	81.5
New Jersey	369.9	443.3	10.9	206.0	1,384.6	0.0	8.5	595.2	2,423.2
North Carolina	0.0	0.0	333.9	0.0	0.0	0.0	0.0	333.9	333.9
Ohio	236.1	0.0	400.2	1.5	0.0	0.0	960.5	1,598.3	1,598.3
Pennsylvania	875.0	1,538.6	1,971.2	5.5	1,718.6	8,545.3	2,069.9	4,921.6	16,724.2
Tennessee	0.0	0.0	0.0	0.0	317.9	0.0	0.0	0.0	317.9
Virginia	404.3	4,562.5	626.5	9.7	1,151.8	0.0	0.0	1,040.5	6,754.8
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	10.5	0.0	1,021.8	0.0	0.0	1,068.9	1,374.4	2,406.7	3,475.6
Total	2,222.8	6,544.5	6,105.3	233.5	5,177.6	9,614.3	12,633.6	21,195.2	42,531.6

Table 7-8 PJM renewable capacity by jurisdiction (MW), on December 31, 2012

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	72.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	2,454.4	2,547.3
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
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	191.1	0.0	7.5	875.9
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	4,706.5	45.9	125.5	37.0	0.0	178.0	1.1	0.0	0.0	500.0	5,594.0
Pennsylvania	35.0	222.0	2,366.7	0.0	1,505.0	682.3	18.0	247.0	1,422.2	1,365.6	7,863.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	121.6	80.0	16.9	3,588.0	457.1	2.7	215.0	0.0	0.0	4,481.3
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	13,340.5	591.4	4,986.5	99.6	5,493.0	2,481.5	248.8	926.1	1,552.2	6,549.2	36,268.8

Table 7-8 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types being renewable.[54] 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 27.6 percent of the total renewable capacity. New Jersey has the highest amount of solar capacity in PJM, 188.8 MW, or 75.1 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 7-9 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not resources offered into PJM wholesale markets. This includes solar capacity of 1,110.6 MW of which 741.8 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 7-9 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.

54 Defined by fuel type, or a generator being registered in PJM GATS. Includes only units that are interconnected to the PJM system.

Table 7-9 Renewable capacity by jurisdiction, non-PJM units registered in GATS[55,56] (MW), on December 31, 2012

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	30.2	0.0	0.1	30.3
Illinois	0.0	6.6	100.4	0.0	0.0	0.0	34.4	0.0	302.5	443.9
Indiana	0.0	0.0	49.7	0.0	679.1	0.0	1.0	0.0	0.0	729.9
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	63.6	0.0	0.3	70.9
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	741.8	0.0	0.4	805.4
New York	0.0	103.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	104.1
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	2.0
Ohio	0.0	1.0	40.3	52.6	67.0	1.0	64.4	109.3	15.9	351.5
Pennsylvania	0.0	5.5	16.2	4.8	87.0	0.3	158.7	0.0	144.0	416.5
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	5.6	318.1	0.0	351.1
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.0	1.3
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	5.9	0.0	0.0	5.9
Total	655.0	140.3	285.9	57.4	833.1	24.6	1,110.6	560.0	609.3	4,276.2

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.

Table 7-10 SO_2 emission controls (FGD) by unit type (MW), as of December 31, 2012

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	53,698.0	25,086.8	78,784.8	68.2%
Combined Cycle	0.0	27,032.1	27,032.1	0.0%
Combustion Turbine	0.0	31,445.4	31,445.4	0.0%
Diesel	0.0	362.8	362.8	0.0%
Non-Coal Steam	0.0	8,746.6	8,746.6	0.0%
Total	53,698.0	92,673.7	146,371.7	36.7%

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 78,784.8 MW of coal steam capacity in PJM, 53,698.0 MW of capacity, 68.2 percent, has some form of FGD technology. Table 7-10 shows emission controls by unit type, of fossil fuel units in PJM.[57]

NO_x emission controlling 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, 133,117.1 MW, or 90.9 percent, of 146,371.7 MW of capacity in PJM, have emission controls for NO_x. Table 7-11 shows NO_X emission controls by unit type of fossil fuel units in PJM. While most units in PJM have NO_x emission controls, many of these controls will need to be upgraded in order to meet forthcoming 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 7-11 NO_x emission controls by unit type (MW), as of December 31, 2012

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	76,027.2	2,757.6	78,784.8	96.5%
Combined Cycle	26,831.1	201.0	27,032.1	99.3%
Combustion Turbine	25,888.0	5,557.4	31,445.4	82.3%
Diesel	0.0	362.8	362.8	0.0%
Non-Coal Steam	4,370.8	4,375.8	8,746.6	50.0%
Total	133,117.1	13,254.6	146,371.7	90.9%

55 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.

56 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed January 01, 2013).

57 See "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed January 15, 2013)

Coal steam units in PJM generally have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter in coal steam units. In PJM, 76,900.8 MW, 97.6 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 7-12 shows particulate emission controls by unit type of fossil fuel units 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 forthcoming 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 7-12 Particulate emission controls by unit type (MW), as of December 31, 2012

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	76,900.8	1,884.0	78,784.8	97.6%
Combined Cycle	0.0	27,032.1	27,032.1	0.0%
Combustion Turbine	0.0	31,445.4	31,445.4	0.0%
Diesel	0.0	362.8	362.8	0.0%
Non-Coal Steam	3,047.0	5,699.6	8,746.6	34.8%
Total	79,947.8	66,423.9	146,371.7	54.6%

Wind Units

Table 7-13 shows the capacity factor of wind units in PJM. In 2012, the capacity factor of wind units in PJM was 25.7 percent. Wind units that were capacity resources had a capacity factor of 26.6 percent and an installed capacity of 4,738 MW. Wind units that were classified as energy only had a capacity factor of 21.3 percent and an installed capacity of 1,811 MW. Much of this wind capacity does not appear in the Capacity Market, as wind capacity in RPM is derated to 13 percent of nameplate capacity, and energy only resources are not included.[58]

Table 7-13 Capacity[59] factor[60] of wind units in PJM: 2012

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Installed Capacity (MW)
Energy-Only Resource	21.3%	NA	1,811
Capacity Resource	26.6%	147.5%	4,738
All Units	25.7%	147.5%	6,549

Beginning June 1, 2009, PJM rules allowed units to submit negative price offers. Table 7-14 presents data on negative offers by wind units. Wind and solar units were the only unit types to make negative offers. On average, 872.4 MW of wind were offered daily at a negative price. Wind units with negative offers were marginal in 4,971 separate five minute intervals, or 4.7 percent of all intervals. On average, 2,566.2 MW of wind were offered daily. Overall, wind units were marginal in 16,342 separate five minute intervals, or 15.5 percent of all intervals. Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they provide a payment to renewable resources in addition to the wholesale price of energy. 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 negative LMP is equal to marginal cost minus the credit received for each MWh. These subsidies affect the offer behavior of these resources in PJM markets.

Table 7-14 Wind resources in real time offering at a negative price in PJM: 2012

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	872.4	4,971	4.7%
All Wind	2,566.2	16,342	15.5%

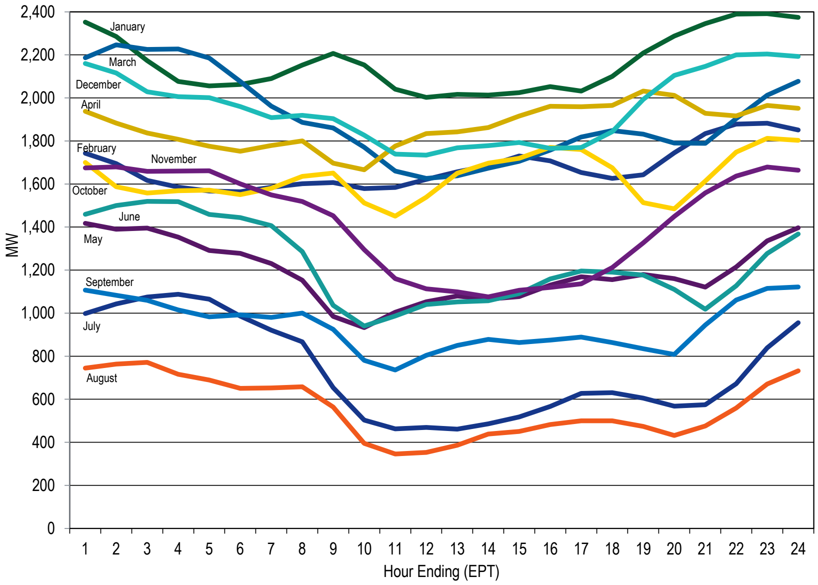
Wind output differs from month to month, based on weather conditions. Figure 7-2 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in January, March and December, and lowest in July and August. The highest average hour, 2,391.2 MW, occurred in January, and the lowest average hour, 345.4 MW, occurred in August. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

58 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.

59 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.

60 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.

Figure 7-2 Average hourly real-time generation of wind units in PJM: 2012



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 7-3 shows the average hourly day-ahead generation of wind units in PJM, by month.

Table 7-15 shows the generation and capacity factor of wind units in each month of 2011 and 2012. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 41.9 percent in January, and the lowest capacity factor was 10.1 percent in August. Overall, the capacity factor in winter months was higher than in summer months. New wind farms came on line throughout 2012, and are included in this analysis as they were added.

Table 7-15 Capacity factor of wind units in PJM by month, 2011 and 2012[61]

	2011		2012	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	909,690.8	28.5%	1,608,349.8	41.9%
February	1,181,192.0	40.5%	1,167,011.9	32.4%
March	1,130,037.9	35.0%	1,416,278.0	35.6%
April	1,329,713.7	42.5%	1,345,643.3	34.7%
May	856,656.7	26.5%	885,583.1	21.6%
June	677,215.5	20.9%	882,597.0	22.2%
July	398,470.5	11.7%	546,676.9	13.3%
August	430,295.2	12.6%	415,544.2	10.1%
September	659,102.8	19.9%	677,039.5	16.9%
October	905,536.3	25.2%	1,213,664.0	27.7%
November	1,432,340.4	39.7%	1,022,628.8	22.9%
December	1,126,776.8	30.0%	1,452,588.7	31.1%
Annual	11,037,028.4	27.6%	12,633,605.2	25.7%

61 Capacity factor shown in Table 7-16 is based on all hours in 2012.

Figure 7-3 Average hourly day-ahead generation of wind units in PJM: 2012

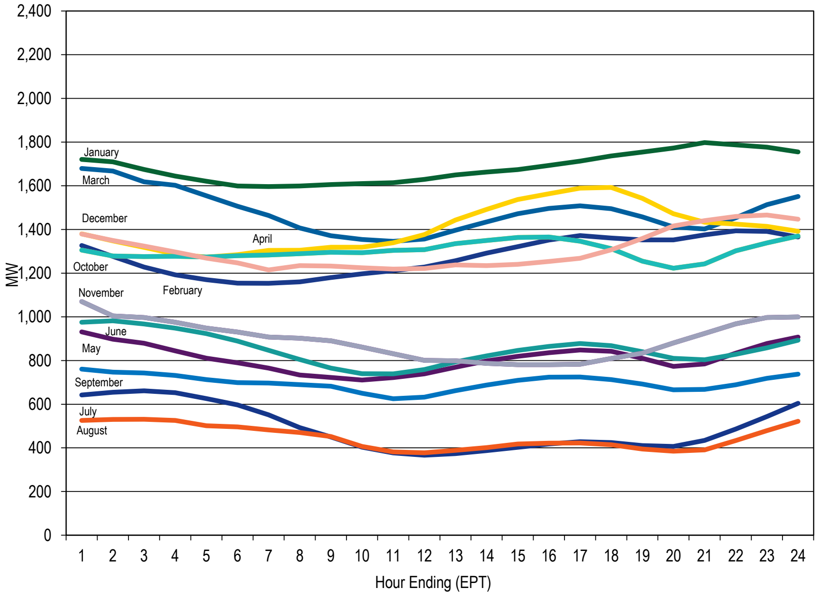
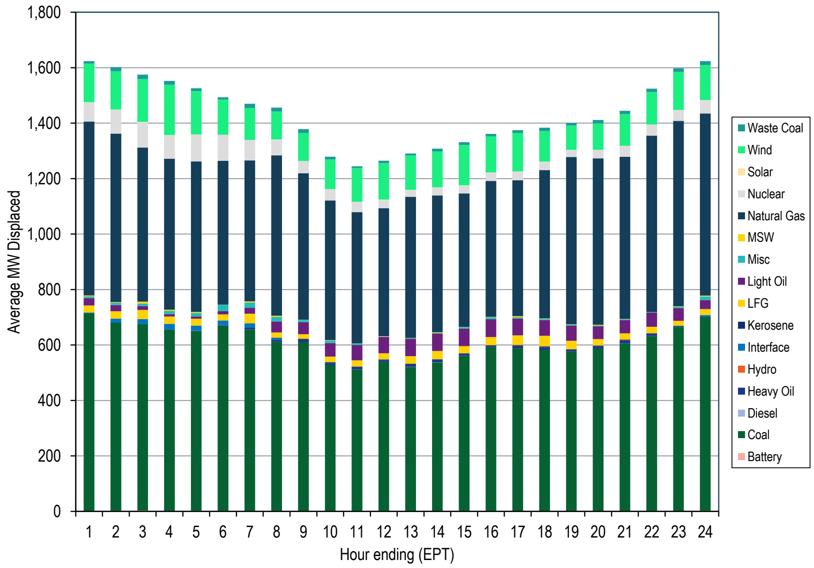


Figure 7-4 Marginal fuel at time of wind generation in PJM: 2012

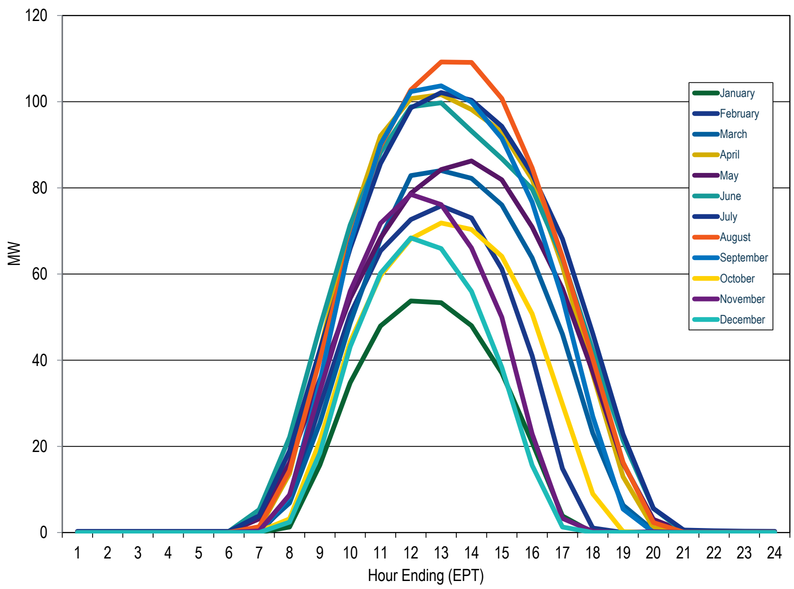


Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output will depend on the level of the wind turbine output, its location, the time of the output and its duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 7-4 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation through 2012. This provides, on an hourly average basis, potentially displaced marginal unit MW by fuel type in 2012. Wind output varies daily, and on average is about 376 MW lower from peak average output (0000 EPT) to lowest average output (1000 EPT). This is not an exact measure because it is not based on a redispatch of the system without wind resources. One result is that wind appears as the displaced fuel at times when wind resources were on the margin. In effect this means that there was no displacement for those hours.

Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 7-5 shows the average hourly real time generation of solar units in PJM, by month. On average, solar generation was highest in August, the month with the highest average hour, 109.2 MW, compared to 248.8 MW of solar installed capacity in PJM. In general, solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 7-5 Average hourly real-time generation of solar units in PJM: 2012



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 take advantage of short-term price differentials. The external regions include both market and non-market balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** PJM was a monthly net exporter of energy in the Real-Time Energy Market in January, August, September, October and December, and a net importer of energy in the remaining months of 2012.[1] The total 2012 real-time net interchange of 2,770.9 GWh (import) was greater than net interchange of -9,761.8 GWh (export) in 2011.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** PJM was a monthly net importer of energy in the Day-Ahead Energy Market in May and June, and a net exporter of energy in the remaining months of 2012. The total 2012 day-ahead net interchange of -12,548.4 GWh (export) was less than net interchange of 6,576.2 GWh (import) in 2011.

  Figure 8-1 shows the correlation between net up-to congestion transactions and the net Day-Ahead Market interchange. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 24,808 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, for 2011.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2012, gross imports in the Day-Ahead Energy Market were 364 percent of the Real-Time Energy Market's gross imports (313 percent for 2011), gross exports in the Day-Ahead Energy Market were 416 percent of the Real-Time Energy Market's gross exports (240 percent for 2011). In 2012, net interchange was -12,548.4 GWh in the Day-Ahead Energy Market and 2,770.9 GWh in the Real-Time Energy Market compared to 6,576.2 GWh in the Day-Ahead Energy Market and -9,761.8 GWh in the Real-Time Energy Market for 2011.
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 69.6 percent of the total net exports: PJM/Eastern Alliant Energy Corporation (ALTE) with 26.5 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 21.8 percent, and PJM/MidAmerican Energy Company (MEC) with 21.3 percent of the net export volume.[2]
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.[3] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 78.4 percent of the total net exports: PJM/MISO with 61.9 percent, and PJM/NYIS with 16.5 percent of the net export volume.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 77.8 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 31.5 percent, PJM/MidAmerican Energy Company (MEC) with 28.0 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 18.4 percent of the net export volume.[4]
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for 2012, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for real-time transactions.[5] The top three net

1 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

3 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

4 In the Day-Ahead Market, two PJM interface had a net interchange of zero (PJM/Carolina Power and Light – Western (CPLW) and PJM/City Water Light & Power (CWLP)).

5 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

exporting interface pricing points in the Day-Ahead Energy Market accounted for 71.3 percent of the total net exports: PJM/SouthEXP with 43.2 percent, PJM/Northwest with 16.6 percent and PJM/ PJM/ Ontario Independent Electricity System Operator (IMO) with 11.6 percent of the net export volume.

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for 2012, up-to congestion transactions had net exports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points for up-to congestion transactions accounted for 65.6 percent of the total net up-to congestion exports: PJM/SouthEXP with 49.1 percent and PJM/Ontario Independent Electricity System Operator (IMO) with 16.5 percent of the net export up-to congestion volume.[6]

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2012, the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average hourly flow. However, the direction of flows was consistent with price differentials in only 47 percent of hours in 2012.
- **PJM and New York ISO Interface Prices.** In 2012, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. However, the direction of flows was consistent with price differentials in only 52.8 percent of the hours in 2012.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2012, the PJM average hourly LMP at the Neptune Interface was $34.14 while the NYISO LMP at the Neptune Bus was $43.92, a difference of $9.78.[7] The average hourly flow during 2012 was -257 MW.[8] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64.5 percent of the hours in 2012.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2012, the average hourly difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average hourly flow. The average hourly flow during 2012 was -72 MW.[9] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 59.5 percent of the hours in 2012.
- **Hudson DC Line.** The Hudson direct current (DC) line will be 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 will be a bidirectional line, power flows will only be from PJM to New York. The Hudson DC line is expected to be in service by the end of the second quarter of 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.

  In 2012, net scheduled interchange was 898 GWh and net actual interchange was 672 GWh, a difference of 226 GWh, compared to net scheduled interchange of -7,072 GWh and net actual interchange of -7,576 GWh, a difference of 504 GWh in 2011.[10] This difference is inadvertent interchange.

6 In the Day-Ahead Market, five PJM interface pricing points (PJM/CPLE, PJM/DUKIMP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

7 In 2012, there were 3,056 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 $32.96 while the NYISO LMP at the Neptune Bus during non-zero flows was $39.70, a difference of $6.74.

8 The average hourly flow during 2012, ignoring hours with no flow, on the Neptune DC Tie line was -393 MW.

9 The average hourly flow during 2012, ignoring hours with no flow, on the Linden VFT line was -89 MW.

10 The "Net Scheduled" values shown in Table 8-18 include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in this table does not match the interchange values shown in Table 8-1 through Table 8-6.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM called fewer TLRs in 2012 than in 2011. The fact that PJM has issued only 37 TLRs in 2012, compared to 62 in 2011, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO.
- **Up-To Congestion.** Following elimination of the requirement to procure transmission for up-to congestion transactions in 2010, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 67,295 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 29,665 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011 (Figure 8-10).
- **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.[11] These modifications are currently being evaluated by PJM.
- **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. 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.

  PJM and MISO have agreed to allow for unlimited spot market ATC on the NYISO Interface. These modifications are currently being evaluated by PJM. The MMU continues to recommend that PJM permit unlimited spot market imports and exports at all PJM Interfaces.

11 See "Meeting Minutes, "Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> . (May 16, 2011)

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 hedging tools (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 2012, 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, and has continued to be a net exporter in most months since that time. The net direction of power flows is generally a result of price differences net of transactions costs. Up-to congestion transactions have played a significant role in power flows between balancing authorities in the Day-Ahead Market since their modification in late 2010.

In 2012, 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 53.3 percent of the hours for transactions between PJM and MISO and for 47.2 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 to the expected actual power flows as possible would result in a more economic dispatch of the entire Eastern Interconnection.

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 equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012. The average of the daily operating reserve rates paid by virtual transactions was $0.56 per MWh for the lowest five percent of all days in 2012.

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. 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.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM was a monthly net exporter of energy in the Real-Time Energy Market in January, August, September, October and December, and a net importer of energy in the remaining months of 2012 (Figure 8-1).[13] The total 2012 real-time net interchange of 2,770.9 GWh was greater than net interchange of -9,761.8 GWh in 2011. The peak month in 2012 for net exporting interchange was December, -337.2 GWh; in 2011 it was September, -1,855.3 GWh. The peak month in 2012 for net importing interchange was November, 1,152.7 GWh; in 2011 it was January, 254.3 GWh. Gross monthly export volumes averaged 3,671.3 GWh compared to 4,251.3 GWh in 2011, while gross monthly imports averaged 3,902.2 GWh compared to 3,437.8 GWh in 2011.

PJM was a monthly net importer of energy in the Day-Ahead Energy Market in May and June, and a net exporter of energy in the remaining months of 2012 (Figure 8-1). The total 2012 day-ahead net interchange of -12,548.4 GWh was less than net interchange of 6,576.2 GWh in 2011. The peak month in 2012 for net exporting interchange was October, -2,696.6 GWh; in 2011 it was November, -1,939.5 GWh. The peak month in 2012 for net importing interchange was May, 2,700.9 GWh; in 2011 it was May, 2,714.6 GWh. Gross monthly export volumes averaged 15,265.8 GWh compared to 10,203.5 GWh in 2011, while gross monthly imports averaged 14,220.1 GWh compared to 10,751.5 GWh in 2011.

Figure 8-1 shows the correlation between net up-to congestion transactions and the net Day-Ahead Market interchange. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 24,808 bids per day, with an average cleared

12 See Docket Nos. ER12-1338-000 and ER12-1343-000.

13 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

volume of 920,307 MWh per day, in 2012, compared to an average of 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, for 2011.

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 in the Day-Ahead and Real-Time Energy Markets.[14] In 2012, gross imports in the Day-Ahead Energy Market were 364 percent of the Real-Time Energy Market's gross imports (313 percent for 2011), gross exports in the Day-Ahead Energy Market were 416 percent of the Real-Time Energy Market's gross exports (240 percent for 2011). In 2012, net interchange was -12,548.4 GWh in the Day-Ahead Energy Market and 2,770.9 GWh in the Real-Time Energy Market compared to 6,576.2 GWh in the Day-Ahead Energy Market and -9,761.8 GWh in the Real-Time Energy Market for 2011.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: 2012

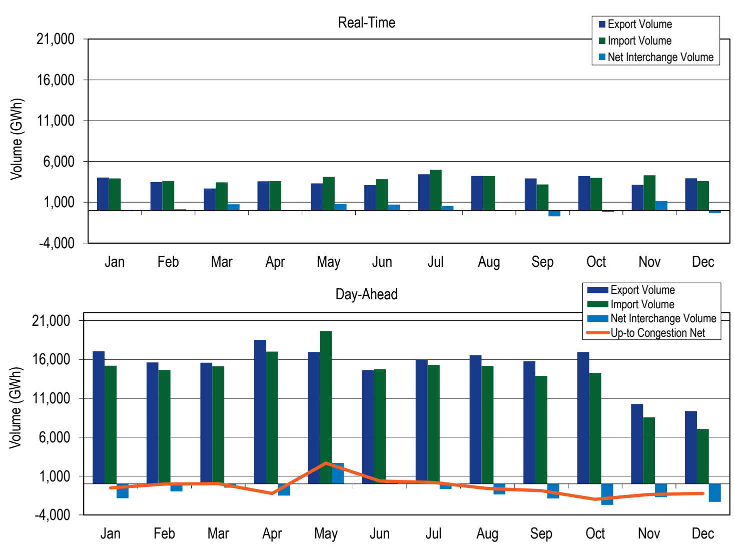


Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 2012

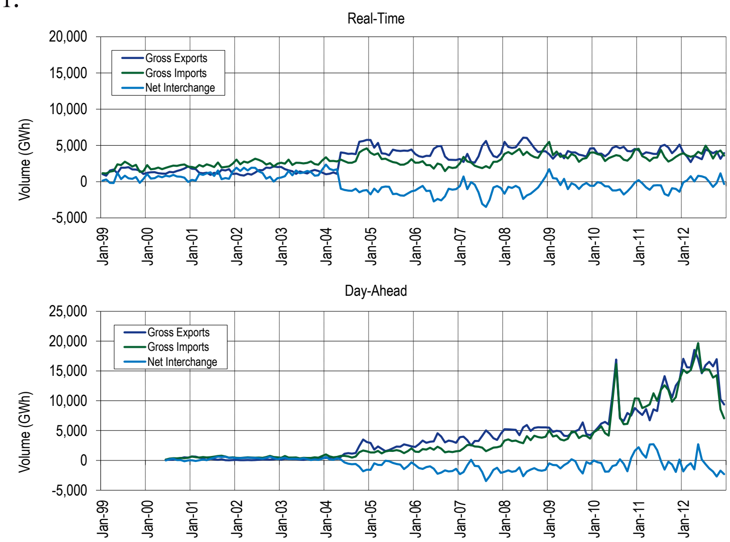


Figure 8-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through 2012. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time. The net direction of power flows is generally a result of price differences net of transactions costs. Up-to congestion transactions have played a significant role in power flows between balancing authorities in the Day-Ahead Market since their modification in late 2010.

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 8-16 for a list of active interfaces in 2012. Figure 8-3 shows the approximate geographic location of the interfaces. In 2012, PJM had 20 interfaces with neighboring balancing authorities. While the Linden

14 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges based on the differences between the transaction MW in the Day-Ahead and Real-Time Markets.

(LIND) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all three are interfaces between PJM and the NYISO. Similarly, there are ten separate interfaces that make up the MISO Interface between the PJM and MISO balancing authorities. Table 8-1 through Table 8-3 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 Market is shown by interface for 2012 in Table 8-1, while gross imports and exports are shown in Table 8-2 and Table 8-3.

In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 69.6 percent of the total net exports: PJM/Eastern Alliant Energy Corporation (ALTE) with 26.5 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 21.8 percent, and PJM/MidAmerican Energy Company (MEC) with 21.3 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 33.2 percent of the total net PJM exports in the Real-Time Energy Market. The ten separate interfaces that connect PJM to MISO together represented 8.9 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 79.1 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 31.8 percent, PJM/Tennessee Valley Authority (TVA) with 27.1 percent and PJM/Michigan Electric Coordinated System (MECS) with 20.2 percent of the net import volume.[15]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of the shares of ownership belong to load serving entities, or their affiliates, within the PJM footprint. The agreement requires delivery of approximately 70 percent of the generation output into the PJM footprint.[16] OVEC itself does not serve load, and therefore does not generally import energy. The nature of the ownership of OVEC and the location of its affiliates within the PJM footprint account for the large percentage of PJM's net interchange import volume.

15 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

16 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (Accessed January 18, 2013).

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(52.5)	(29.2)	(27.8)	(34.3)	(15.3)	(22.7)	238.8	232.1	(30.4)	(32.4)	(36.6)	(45.8)	143.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1
DUK	98.9	(85.3)	(13.0)	(73.2)	160.6	46.6	114.7	(9.7)	30.1	75.9	24.3	1.5	371.5
EKPC	(37.5)	(19.2)	(14.3)	(61.9)	(52.8)	(71.2)	(59.8)	(69.8)	(165.8)	(174.1)	(115.8)	(83.5)	(925.8)
LGEE	357.0	141.4	128.3	181.6	35.0	194.3	279.5	239.8	239.8	331.3	334.5	224.4	2,686.8
MEC	(468.8)	(446.6)	(430.5)	(400.2)	(482.9)	(467.3)	(485.4)	(475.5)	(475.9)	(490.6)	(463.1)	(303.2)	(5,389.9)
MISO	(368.7)	(141.8)	452.0	(380.6)	(366.3)	(154.8)	(1,028.6)	(214.7)	(236.7)	(575.2)	770.7	(15.3)	(2,259.9)
ALTE	(693.8)	(557.5)	(179.2)	(651.7)	(653.7)	(453.4)	(799.3)	(599.4)	(516.2)	(807.9)	(324.4)	(483.2)	(6,719.8)
ALTW	(49.7)	(22.7)	(4.9)	(12.9)	(32.6)	(12.1)	(9.5)	(42.6)	(16.4)	(31.8)	(15.0)	(32.0)	(282.2)
AMIL	17.7	39.9	106.3	(55.2)	(17.2)	(17.1)	146.1	151.3	133.3	146.2	248.2	249.6	1,148.9
CIN	377.7	179.8	300.2	241.2	13.5	87.1	(254.9)	161.4	41.5	(32.8)	233.9	162.2	1,510.7
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(172.2)	(76.5)	27.6	(123.5)	(162.6)	(72.9)	(224.2)	(98.3)	(202.1)	(193.4)	32.1	(72.4)	(1,338.5)
MECS	378.4	488.4	348.5	366.7	551.8	494.4	355.0	436.8	472.1	676.9	720.4	392.7	5,682.2
NIPS	(18.4)	(17.4)	14.3	10.4	19.3	(39.8)	(83.9)	(30.9)	76.8	(36.3)	(13.5)	(52.9)	(172.3)
WEC	(208.4)	(175.8)	(160.7)	(155.5)	(84.7)	(140.9)	(157.9)	(193.1)	(225.6)	(296.1)	(111.0)	(179.3)	(2,089.0)
NYISO	(1,127.3)	(750.9)	(508.4)	(317.8)	(110.2)	(396.7)	(577.6)	(1,168.5)	(869.2)	(523.8)	(825.8)	(1,228.7)	(8,404.8)
LIND	(63.9)	(6.3)	(64.5)	(60.6)	33.1	(39.4)	(62.6)	(119.1)	(77.0)	(8.5)	(8.2)	(159.3)	(636.3)
NEPT	(415.7)	(329.7)	(288.4)	(155.4)	(119.8)	0.0	(1.4)	(275.7)	(237.1)	(64.6)	(109.1)	(256.5)	(2,253.2)
NYIS	(647.8)	(414.9)	(155.5)	(101.8)	(23.5)	(357.3)	(513.5)	(773.8)	(555.1)	(450.7)	(708.4)	(812.9)	(5,515.3)
OVEC	712.5	693.4	588.3	627.1	835.9	714.4	834.9	745.2	526.7	814.1	1,007.9	825.6	8,925.8
TVA	783.0	787.2	580.6	485.4	794.0	883.5	1,229.6	703.0	254.9	377.9	456.6	287.7	7,623.4
Total	(103.4)	149.0	755.1	26.1	798.0	726.0	546.2	(18.2)	(726.5)	(196.8)	1,152.7	(337.2)	2,770.9

Table 8-2 Real-time scheduled gross import volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	0.3	0.0	0.4	1.6	2.1	2.7	274.0	256.4	0.0	0.9	0.0	2.4	540.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1
DUK	277.1	168.8	134.8	187.5	288.2	142.0	268.7	167.6	120.5	149.4	198.6	115.7	2,218.9
EKPC	41.0	31.5	26.7	3.2	8.1	7.6	30.2	24.2	3.4	1.3	8.4	14.3	199.9
LGEE	365.4	147.0	149.7	186.2	94.6	204.4	282.2	244.2	243.3	331.4	335.2	252.0	2,835.6
MEC	16.9	7.3	0.1	0.2	0.2	0.0	0.0	0.3	1.3	0.0	7.0	181.0	214.2
MISO	1,179.1	1,022.7	1,025.3	1,229.0	1,147.9	929.4	991.6	1,112.4	1,187.9	1,420.6	1,534.9	1,132.0	13,912.7
ALTE	1.3	4.8	0.2	0.0	0.6	0.0	0.0	3.8	3.9	0.0	0.1	0.0	14.7
ALTW	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	0.0	1.5
AMIL	46.5	78.1	134.2	13.5	24.3	34.1	201.4	172.2	183.7	194.1	273.2	295.8	1,651.1
CIN	526.9	330.4	340.5	530.7	379.8	314.7	216.9	288.7	312.4	376.1	392.7	362.2	4,372.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	127.3	88.2	126.3	94.8	60.7	58.4	67.5	52.9	58.5	124.6	103.0	64.4	1,026.5
MECS	408.3	520.4	390.7	519.7	598.0	521.5	504.1	587.9	503.9	713.5	726.1	409.7	6,403.8
NIPS	59.4	0.7	32.5	70.2	84.0	0.7	1.6	6.3	125.5	12.1	38.3	0.0	431.3
WEC	9.6	0.0	0.9	0.0	0.6	0.0	0.0	0.7	0.0	0.2	0.1	0.0	11.9
NYISO	506.4	678.4	887.4	824.9	886.8	883.2	1,004.0	900.4	818.0	883.6	718.2	759.4	9,750.6
LIND	10.7	19.6	12.2	18.6	52.2	25.0	33.4	21.0	14.1	35.6	0.0	1.8	244.3
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	495.6	658.7	875.1	806.3	834.6	858.2	970.6	879.5	803.9	848.0	718.2	757.6	9,506.3
OVEC	738.2	716.7	611.5	647.2	856.0	731.7	853.5	763.8	544.3	832.3	1,029.0	847.4	9,171.8
TVA	802.8	845.0	610.7	510.0	835.2	927.7	1,272.0	742.8	273.1	386.6	471.8	303.7	7,981.3
Total	3,927.2	3,617.4	3,446.6	3,589.7	4,118.9	3,828.7	4,976.3	4,212.1	3,191.9	4,006.1	4,303.1	3,608.0	46,825.9

Table 8-3 Real-time scheduled gross export volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	52.8	29.2	28.2	35.9	17.4	25.5	35.2	24.3	30.5	33.3	36.6	48.1	397.0
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	178.2	254.1	147.7	260.6	127.6	95.4	154.0	177.3	90.5	73.5	174.3	114.2	1,847.4
EKPC	78.5	50.7	41.1	65.1	60.8	78.8	90.0	94.0	169.2	175.3	124.1	97.8	1,125.6
LGEE	8.4	5.6	21.4	4.6	59.6	10.1	2.7	4.4	3.5	0.2	0.8	27.6	148.9
MEC	485.7	453.9	430.5	400.4	483.0	467.3	485.4	475.8	477.2	490.6	470.1	484.2	5,604.1
MISO	1,547.8	1,164.5	573.3	1,609.6	1,514.2	1,084.1	2,020.2	1,327.2	1,424.6	1,995.8	764.2	1,147.3	16,172.7
ALTE	695.1	562.3	179.5	651.7	654.4	453.4	799.3	603.2	520.1	807.9	324.4	483.2	6,734.4
ALTW	49.7	22.8	4.9	12.9	32.6	12.1	9.5	42.6	16.4	31.8	16.4	32.0	283.7
AMIL	28.7	38.3	28.0	68.7	41.5	51.2	55.3	20.9	50.4	47.9	25.0	46.2	502.1
CIN	149.2	150.6	40.3	289.6	366.4	227.6	471.9	127.3	270.9	408.9	158.8	200.0	2,861.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	299.5	164.7	98.7	218.3	223.3	131.3	291.7	151.2	260.6	318.0	70.9	136.7	2,364.9
MECS	29.9	32.0	42.2	153.0	46.1	27.1	149.1	151.1	31.9	36.6	5.6	17.0	721.6
NIPS	77.8	18.1	18.2	59.8	64.7	40.5	85.5	37.2	48.7	48.4	51.9	52.9	603.6
WEC	218.0	175.8	161.6	155.5	85.3	140.9	157.9	193.7	225.6	296.3	111.1	179.3	2,100.9
NYISO	1,633.7	1,429.2	1,395.7	1,142.7	997.0	1,279.9	1,581.6	2,069.0	1,687.2	1,407.4	1,543.9	1,988.2	18,155.5
LIND	74.6	26.0	76.7	79.2	19.1	64.4	96.0	140.0	91.1	44.1	8.2	161.1	880.7
NEPT	415.7	329.7	288.4	155.4	119.8	0.0	1.4	275.7	237.1	64.6	109.1	256.5	2,253.2
NYIS	1,143.4	1,073.6	1,030.6	908.1	858.1	1,215.6	1,484.1	1,653.2	1,359.0	1,298.7	1,426.6	1,570.6	15,021.6
OVEC	25.7	23.3	23.3	20.1	20.1	17.3	18.6	18.6	17.7	18.2	21.2	21.8	246.0
TVA	19.8	57.8	30.2	24.6	41.2	44.1	42.4	39.8	18.2	8.7	15.2	15.9	357.9
Total	4,030.6	3,468.4	2,691.5	3,563.6	3,320.9	3,102.7	4,430.2	4,230.3	3,918.4	4,202.9	3,150.4	3,945.2	44,055.0

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.[17] 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. 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.[18]

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.[19] 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

17 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.

18 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.

19 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed January 16, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

set of weighting factors for each external pricing point in an interface price definition.[20] 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 8-17 presents the interface pricing points used in 2012.

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.

Real-Time Energy Market transaction prices are determined based on transaction details as defined below:

- **Real-Time Energy Market Imports:** For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface pricing point as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA's Interface pricing point (i.e. SouthIMP). At the time the energy is scheduled, if the GCA on the NERC Tag shows that the physical flow would enter PJM at an interface other than the SouthIMP Interface pricing point, the source would then default to that new interface pricing point. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.
- **Real-Time Energy Market Exports:** For a real-time export energy transaction, when a market participant selects the POR and POD on their OASIS reservation, the sink defaults to the associated interface pricing point as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is TVA, the sink would initially default to TVA's Interface pricing point (i.e. SouthEXP). At the time the energy is scheduled, if the LCA on the NERC Tag shows that the physical flow would leave PJM at an interface other than the SouthEXP Interface pricing point, the sink would then default to that new interface pricing point. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.
- **Real-Time Energy Market Wheels:** For a real-time wheel through energy transaction, when a market participant selects the POR and POD on their OASIS reservation, both the source and sink default to the associated interface pricing point as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface pricing point (i.e. SouthIMP), and the sink would initially default to NYIS's Interface pricing point (i.e. NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag shows that the physical flow would enter PJM at an interface other than the SouthIMP Interface pricing point, the source would then default to that new interface pricing point. Similarly, if the LCA on the NERC Tag shows that the physical flow would leave PJM at an interface other than the NYIS Interface pricing point, the sink would then default to that new interface pricing point.

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

20 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>. (January 16, 2013)

agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[21]

In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.[22] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 78.4 percent of the total net exports: PJM/MISO with 61.9 percent, and PJM/NYIS with 16.5 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 25.5 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 77.6 percent of the total net imports: PJM/SouthIMP with 52.0 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 25.5 percent of the net import volume.

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	479.8	485.2	431.3	551.8	426.9	377.8	420.8	370.8	379.2	656.7	745.9	555.1	5,881.3
LINDENVFT	(63.9)	(6.3)	(64.5)	(60.6)	33.1	(39.4)	(62.6)	(119.1)	(77.0)	(8.5)	(8.2)	(159.3)	(636.3)
MISO	(1,992.3)	(1,601.0)	(940.0)	(1,985.0)	(1,934.8)	(1,496.7)	(2,196.9)	(1,565.4)	(1,671.9)	(2,254.3)	(934.9)	(1,356.1)	(19,929.4)
NEPTUNE	(415.7)	(329.7)	(288.4)	(155.4)	(119.8)	0.0	(1.4)	(275.7)	(237.1)	(64.6)	(109.1)	(256.5)	(2,253.2)
NORTHWEST	(1.6)	(1.5)	(1.2)	(3.5)	(21.2)	(0.3)	(55.0)	(25.2)	(1.5)	(2.3)	(2.4)	(1.5)	(117.1)
NYIS	(648.1)	(415.3)	(166.8)	(103.3)	(30.4)	(355.7)	(482.9)	(722.7)	(489.3)	(433.4)	(673.0)	(793.7)	(5,314.6)
OVEC	712.5	693.4	588.3	627.1	835.9	714.4	834.9	745.2	526.7	814.1	1,007.9	825.6	8,925.8
SOUTHIMP	2,164.4	1,722.9	1,465.1	1,550.6	1,920.1	1,783.4	2,432.6	1,919.0	1,163.6	1,387.3	1,478.5	1,155.6	20,143.1
CPLEIMP	0.0	0.0	0.4	1.0	1.4	2.4	273.5	256.4	0.0	0.2	0.0	0.0	535.1
DUKIMP	106.7	88.6	56.7	61.8	111.9	56.9	219.9	129.2	74.3	71.3	53.2	46.1	1,076.5
NCMPAIMP	44.7	44.2	25.2	21.8	72.6	41.5	25.6	24.8	15.8	12.0	9.9	10.3	348.4
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	1,465.9	1,734.2	1,682.5	1,913.7	1,508.6	1,073.5	1,303.9	1,415.4	1,099.2	18,183.0
SOUTHEXP	(338.5)	(398.7)	(268.6)	(395.7)	(311.9)	(257.4)	(343.3)	(345.2)	(319.2)	(291.8)	(351.9)	(306.4)	(3,928.6)
CPLEEXP	(52.8)	(26.6)	(26.0)	(31.3)	(16.9)	(24.3)	(30.9)	(24.0)	(29.0)	(33.0)	(23.8)	(48.1)	(366.7)
DUKEXP	(172.0)	(233.9)	(141.2)	(243.9)	(108.8)	(74.2)	(129.2)	(157.4)	(74.7)	(48.9)	(128.9)	(86.4)	(1,599.5)
NCMPAEXP	0.0	0.0	0.0	(2.6)	0.0	0.0	0.0	0.0	0.0	0.0	(1.3)	(0.9)	(4.8)
SOUTHWEST	(1.6)	(1.3)	0.0	(4.2)	(5.0)	(3.5)	(10.9)	(5.1)	(7.4)	(0.6)	(0.3)	(2.4)	(42.0)
SOUTHEXP	(112.1)	(136.9)	(101.4)	(113.7)	(181.2)	(155.5)	(172.3)	(158.7)	(208.2)	(209.4)	(197.6)	(168.7)	(1,915.6)
Total	(103.4)	149.0	755.1	26.1	798.0	726.0	546.2	(18.2)	(726.5)	(196.8)	1,152.7	(337.2)	2,770.9

21 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.

22 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	480.4	486.8	434.3	554.0	433.1	385.6	443.5	389.1	400.8	658.6	747.8	558.8	5,972.9
LINDENVFT	10.7	19.6	12.2	18.6	52.2	25.0	33.4	21.0	14.1	35.6	0.0	1.8	244.3
MISO	38.8	14.6	62.0	15.3	31.4	47.6	225.4	205.4	210.7	227.8	295.6	271.2	1,645.8
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.2	0.0	0.0	0.4
NYIS	494.6	656.7	861.4	804.0	826.0	855.5	987.8	913.8	858.3	864.2	752.2	773.2	9,647.7
OVEC	738.2	716.7	611.5	647.2	856.0	731.7	853.5	763.8	544.3	832.3	1,029.0	847.4	9,171.8
SOUTHIMP	2,164.4	1,722.9	1,465.1	1,550.6	1,920.1	1,783.4	2,432.6	1,919.0	1,163.6	1,387.3	1,478.5	1,155.6	20,143.1
CPLEIMP	0.0	0.0	0.4	1.0	1.4	2.4	273.5	256.4	0.0	0.2	0.0	0.0	535.1
DUKIMP	106.7	88.6	56.7	61.8	111.9	56.9	219.9	129.2	74.3	71.3	53.2	46.1	1,076.5
NCMPAIMP	44.7	44.2	25.2	21.8	72.6	41.5	25.6	24.8	15.8	12.0	9.9	10.3	348.4
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	1,465.9	1,734.2	1,682.5	1,913.7	1,508.6	1,073.5	1,303.9	1,415.4	1,099.2	18,183.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3,927.2	3,617.4	3,446.6	3,589.7	4,118.9	3,828.7	4,976.3	4,212.1	3,191.9	4,006.1	4,303.1	3,608.0	46,825.9

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	0.7	1.6	3.1	2.2	6.2	7.7	22.6	18.3	21.6	1.9	1.9	3.7	91.6
LINDENVFT	74.6	26.0	76.7	79.2	19.1	64.4	96.0	140.0	91.1	44.1	8.2	161.1	880.7
MISO	2,031.1	1,615.6	1,002.0	2,000.3	1,966.2	1,544.3	2,422.3	1,770.8	1,882.7	2,482.2	1,230.5	1,627.3	21,575.1
NEPTUNE	415.7	329.7	288.4	155.4	119.8	0.0	1.4	275.7	237.1	64.6	109.1	256.5	2,253.2
NORTHWEST	1.6	1.5	1.2	3.5	21.2	0.3	55.1	25.2	1.5	2.6	2.4	1.5	117.5
NYIS	1,142.8	1,072.0	1,028.2	907.3	856.4	1,211.2	1,470.7	1,636.5	1,347.6	1,297.6	1,425.2	1,566.9	14,962.3
OVEC	25.7	23.3	23.3	20.1	20.1	17.3	18.6	18.6	17.7	18.2	21.2	21.8	246.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	338.5	398.7	268.6	395.7	311.9	257.4	343.3	345.2	319.2	291.8	351.9	306.4	3,928.6
CPLEEXP	52.8	26.6	26.0	31.3	16.9	24.3	30.9	24.0	29.0	33.0	23.8	48.1	366.7
DUKEXP	172.0	233.9	141.2	243.9	108.8	74.2	129.2	157.4	74.7	48.9	128.9	86.4	1,599.5
NCMPAEXP	0.0	0.0	0.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.9	4.8
SOUTHWEST	1.6	1.3	0.0	4.2	5.0	3.5	10.9	5.1	7.4	0.6	0.3	2.4	42.0
SOUTHEXP	112.1	136.9	101.4	113.7	181.2	155.5	172.3	158.7	208.2	209.4	197.6	168.7	1,915.6
Total	4,030.6	3,468.4	2,691.5	3,563.6	3,320.9	3,102.7	4,430.2	4,230.3	3,918.4	4,202.9	3,150.4	3,945.2	44,055.0

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.[23] 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, 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.

A fixed Day-Ahead Energy Market transaction request means that the market participant agrees to be a price taker for the MW amount of the offer. There is no price associated with the request and the market participant agrees to take the day-ahead LMP at the associated import or export pricing point. If the market participant has met the required deadline and has acquired a valid willing-to-pay congestion OASIS reservation, a fixed day-ahead transaction request will be accepted in the Day-Ahead Energy Market. These approved transactions are a financial obligation. If the market participant does not provide a corresponding transaction in the Real-Time Energy Market, they are subject to the balancing market settlement.

To submit an up-to congestion offer, the market participant is required to submit an energy profile (start time, stop time and MW value) and specify the amount of congestion they are willing to pay.[24] If, in the Day-Ahead Energy Market, congestion on the desired path is less than that specified, the up-to congestion request is approved. Approved up-to congestion offers are financial obligations. If the market participant does not provide a corresponding transaction in the Real-Time Energy Market, they are subject to the balancing market settlement.

Dispatchable transactions in the Day-Ahead Energy Market are similar to those in the Real-Time Energy Market in that they are evaluated against a floor or ceiling price at the designated import or export pricing point. For import dispatchable transactions, if the LMP at the interface clears higher than the specified bid, the transaction is approved. For export dispatchable transactions, if the LMP at the interface clears lower than the specified bid, the transaction is approved. As with fixed and up-to congestion transactions, cleared dispatchable transactions in the Day-Ahead Energy Market represent a financial obligation. If the market participant does not meet the commitment in the Real-Time Energy Market, they are subject to the balancing market settlement.

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants.

- **Day-Ahead Energy Market Imports:** For day-ahead import energy transactions, the market participant chooses any import pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.
- **Day-Ahead Energy Market Exports:** For day-ahead export energy transactions, the market participant chooses any export pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.
- **Day-Ahead Energy Market Wheels: F**or day-ahead wheel through energy transactions, the market

23 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.

24 Effective May 15, 2012, up-to congestion transactions were required to be submitted for the PJM Day-Ahead Market evaluation in the eMarket application, and are no longer accepted through the EES application.

participant chooses any import pricing point and export pricing point they wish to have associated with their transaction. These selections are made through the EES user interface.

Because market participants choose the interface pricing point(s) they wish to have associated with their transaction in the Day-Ahead Energy Market, the scheduled interface is less meaningful than in the Real-Time Energy Market. In Table 8-7, Table 8-8 and Table 8-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not necessarily match that of 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.

On May 15, 2012, the submission of up-to congestion transactions was moved to the eMKT application. The submission of up-to congestion transactions in eMKT no longer requires market participants to acquire the up-to congestion OASIS reservation. This change eliminates all references to any specific interface previously identified by the OASIS reservation, and only identifies the relevant interface pricing points for the up-to congestion transaction as specified by the market participants at the time of submission. As a result, the up-to congestion transactions shown in the tables have been removed from the interface specific totals, and are now represented only as a single monthly total. Table 8-7 through Table 8-9 show the Day-Ahead interchange totals at the individual interfaces. Net interchange in the Day-Ahead Market is shown by interface for 2012 in Table 8-7, while gross imports and exports are shown in Table 8-8 and Table 8-9.

In the Day-Ahead Energy Market, for 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 77.8 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 31.5 percent, PJM/MidAmerican Energy Company (MEC) with 28.0 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 18.4 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 43.2 percent of the total net PJM exports in the Day-Ahead Energy Market. The ten separate interfaces that connect PJM to MISO together represented 12.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interfaces had net scheduled imports, with three importing interfaces accounting for 87.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 56.4 percent, PJM/Tennessee Valley Authority (TVA) with 13.6 percent and PJM/Michigan Electric Coordinated System (MECS) with 11.7 percent of the net import volume.[25]

25 In the Day-Ahead Market, two PJM interface had a net interchange of zero (PJM/Carolina Power and Light – Western (CPLW) and PJM/City Water Light & Power (CWLP)).

Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(46.8)	(19.9)	(24.9)	(29.6)	(15.3)	(23.9)	(8.8)	182.6	(27.6)	(33.0)	(23.3)	(43.9)	(114.3)
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	39.0	18.6	19.8	11.3	40.4	35.5	29.5	96.6	35.2	39.4	26.5	35.7	427.5
EKPC	(35.6)	(34.8)	(37.2)	(36.0)	(37.2)	(36.0)	(37.2)	(36.6)	(36.0)	(37.2)	(36.1)	(37.2)	(437.0)
LGEE	52.9	0.0	(18.6)	4.6	12.3	39.2	50.8	18.1	48.4	59.0	102.3	72.5	441.5
MEC	(485.7)	(454.2)	(429.3)	(386.5)	(482.1)	(462.9)	(470.7)	(472.7)	(461.3)	(480.5)	(468.7)	(483.6)	(5,538.1)
MISO	(426.3)	(243.4)	114.8	(13.8)	(86.8)	(5.5)	(507.0)	(280.0)	(188.6)	(377.7)	(100.9)	(357.2)	(2,472.6)
ALTE	(474.1)	(476.4)	(145.4)	(410.0)	(243.1)	(170.6)	(438.6)	(356.9)	(204.6)	(318.0)	(132.9)	(261.1)	(3,631.7)
ALTW	(26.1)	(7.8)	(2.6)	(2.4)	(6.1)	(6.6)	(0.8)	(22.5)	(1.7)	(18.0)	(11.7)	(29.6)	(135.8)
AMIL	(3.1)	0.0	0.0	0.8	0.0	2.4	0.0	0.8	3.6	1.4	4.8	(1.0)	9.7
CIN	130.6	205.2	236.5	322.4	59.2	131.0	(90.5)	91.3	91.4	(2.6)	30.8	30.3	1,235.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(15.0)	(10.2)	(1.9)	(5.1)	(10.9)	(7.9)	(27.0)	(13.8)	(16.6)	(13.1)	(7.1)	(11.8)	(140.5)
MECS	81.3	148.4	112.3	183.2	177.4	115.5	128.7	133.8	58.2	82.9	128.8	34.0	1,384.5
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	(3.8)	(33.3)	(46.4)	(46.2)	(51.1)	(50.0)	(230.8)
WEC	(119.9)	(102.6)	(84.1)	(102.5)	(63.2)	(69.4)	(75.0)	(79.4)	(72.6)	(64.1)	(62.5)	(68.1)	(963.3)
NYISO	(1,175.9)	(928.5)	(661.4)	(399.5)	(302.6)	(458.5)	(679.2)	(966.4)	(821.6)	(613.4)	(690.2)	(856.7)	(8,553.8)
LIND	(10.2)	(2.2)	(7.2)	(0.7)	29.3	1.2	10.3	3.0	(2.4)	19.9	0.0	(3.3)	37.7
NEPT	(425.2)	(355.9)	(314.5)	(160.0)	(142.8)	0.0	(9.2)	(274.5)	(244.4)	(70.4)	(109.7)	(262.7)	(2,369.3)
NYIS	(740.4)	(570.4)	(339.7)	(238.8)	(189.2)	(459.8)	(680.3)	(694.9)	(574.8)	(562.9)	(580.5)	(590.7)	(6,222.2)
OVEC	545.7	521.4	440.8	472.6	625.9	552.9	640.1	548.9	379.4	610.5	726.9	584.8	6,649.8
TVA	204.7	195.9	92.8	95.4	275.9	136.6	156.9	147.4	64.6	116.5	104.7	5.6	1,597.0
Total without Up-To Congestion	(1,327.9)	(945.0)	(503.3)	(281.4)	30.5	(222.7)	(825.6)	(762.2)	(1,007.4)	(716.4)	(358.7)	(1,080.1)	(8,000.1)
Up-To Congestion	(519.6)	(17.7)	28.2	(1,223.6)	2,670.4	364.2	177.9	(586.8)	(872.8)	(1,980.3)	(1,354.7)	(1,233.5)	(4,548.3)
Total	(1,847.5)	(962.7)	(475.1)	(1,505.0)	2,700.9	141.5	(647.7)	(1,349.0)	(1,880.2)	(2,696.6)	(1,713.4)	(2,313.6)	(12,548.4)

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	0.0	0.0	0.0	0.0	0.0	0.0	27.6	204.2	0.0	0.0	0.0	0.0	231.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	40.8	47.9	32.8	18.9	41.2	35.5	35.4	116.5	35.2	39.4	28.4	35.7	507.8
EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LGEE	52.9	0.0	0.0	4.6	12.3	39.2	50.8	18.1	48.4	59.0	102.3	72.5	460.1
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	0.8
MISO	217.0	367.5	359.3	522.0	385.0	336.6	249.9	294.8	273.1	345.0	222.9	131.5	3,704.7
ALTE	0.0	0.0	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	0.0	1.5
AMIL	0.4	0.0	0.0	0.8	0.0	2.4	0.0	0.8	3.6	1.4	4.8	1.3	15.5
CIN	135.3	219.1	247.0	336.5	207.7	218.7	120.8	149.6	210.2	254.7	87.8	92.2	2,279.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1
MECS	81.3	148.4	112.3	183.2	177.4	115.5	129.0	144.5	59.3	88.9	128.8	38.0	1,406.5
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	359.7	533.6	728.6	655.1	688.1	717.4	790.0	766.6	684.3	735.2	564.6	651.1	7,874.3
LIND	0.0	1.4	1.7	7.7	32.8	6.4	18.9	14.8	5.0	23.9	0.0	0.3	112.9
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	359.7	532.3	726.9	647.4	655.3	710.9	771.1	751.8	679.4	711.3	564.6	650.7	7,761.4
OVEC	571.3	544.6	464.0	491.4	645.9	552.9	640.1	567.3	397.1	610.5	726.9	584.8	6,797.0
TVA	217.7	223.7	100.5	105.5	307.3	149.1	165.0	150.1	64.8	117.1	111.2	8.0	1,720.0
Total without Up-To Congestion	1,459.4	1,717.4	1,685.2	1,797.4	2,079.8	1,830.6	1,958.9	2,117.7	1,503.9	1,906.3	1,756.4	1,483.5	21,296.4
Up-To Congestion	13,728.0	12,936.0	13,418.2	15,214.5	17,586.0	12,925.9	13,350.2	13,068.1	12,381.2	12,361.9	6,804.3	5,570.9	149,345.1
Total	15,187.4	14,653.3	15,103.4	17,011.9	19,665.8	14,756.4	15,309.1	15,185.8	13,885.1	14,268.1	8,560.7	7,054.4	170,641.5

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	46.8	19.9	24.9	29.6	15.3	23.9	36.4	21.5	27.6	33.0	23.3	43.9	346.1
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	1.8	29.3	13.0	7.6	0.8	0.0	5.9	20.0	0.0	0.0	1.9	0.0	80.3
EKPC	35.6	34.8	37.2	36.0	37.2	36.0	37.2	36.6	36.0	37.2	36.1	37.2	437.0
LGEE	0.0	0.0	18.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.6
MEC	485.7	454.2	429.3	386.5	482.1	462.9	470.7	472.7	462.1	480.5	468.7	483.6	5,538.9
MISO	643.3	611.0	244.5	535.8	471.8	342.1	757.0	574.9	461.7	722.8	323.8	488.7	6,177.3
ALTE	474.1	476.4	145.4	411.6	243.1	170.6	438.6	356.9	204.6	318.0	132.9	261.1	3,633.3
ALTW	26.1	7.8	2.6	2.4	6.1	6.6	0.8	22.5	1.7	18.0	13.2	29.6	137.3
AMIL	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	5.9
CIN	4.7	13.9	10.5	14.1	148.5	87.7	211.3	58.2	118.8	257.4	57.0	61.9	1,044.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	15.0	10.2	1.9	5.1	10.9	7.9	27.1	13.8	16.6	13.1	7.1	11.8	140.6
MECS	0.0	0.0	0.0	0.0	0.0	0.0	0.3	10.7	1.1	6.0	0.0	4.0	22.1
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	3.8	33.3	46.4	46.2	51.1	50.0	230.8
WEC	119.9	102.6	84.1	102.5	63.2	69.4	75.0	79.4	72.6	64.1	62.5	68.1	963.3
NYISO	1,535.5	1,462.1	1,390.0	1,054.5	990.7	1,175.9	1,469.2	1,733.0	1,505.9	1,348.7	1,254.9	1,507.8	16,428.1
LIND	10.2	3.6	8.9	8.4	3.4	5.2	8.6	11.9	7.4	4.0	0.0	3.6	75.2
NEPT	425.2	355.9	314.5	160.0	142.8	0.0	9.2	274.5	244.4	70.4	109.7	262.7	2,369.3
NYIS	1,100.1	1,102.7	1,066.6	886.2	844.5	1,170.7	1,451.4	1,446.7	1,254.1	1,274.2	1,145.1	1,241.4	13,983.6
OVEC	25.6	23.3	23.3	18.8	20.1	0.0	0.0	18.5	17.7	0.0	0.0	0.0	147.2
TVA	13.0	27.8	7.7	10.1	31.4	12.5	8.2	2.7	0.3	0.6	6.5	2.4	123.0
Total without Up-To Congestion	2,787.3	2,662.4	2,188.5	2,078.8	2,049.3	2,053.3	2,784.5	2,879.9	2,511.2	2,622.6	2,115.1	2,563.6	29,296.5
Up-To Congestion	14,247.6	12,953.7	13,390.0	16,438.1	14,915.6	12,561.6	13,172.3	13,654.9	13,254.1	14,342.2	8,159.0	6,804.4	153,893.4
Total	17,034.9	15,616.0	15,578.5	18,516.9	16,964.9	14,614.9	15,956.8	16,534.8	15,765.3	16,964.8	10,274.1	9,368.0	183,189.9

Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-15 show the Day-Ahead Market interchange totals at the individual interface pricing points. Up-to congestion transactions account for 87.5 percent of all scheduled import MW transactions and 84.0 percent of all scheduled export MW transactions in the Day-Ahead Market. Net interchange in the Day-Ahead Market, including up-to congestion transactions, is shown by interface pricing point for 2012 in Table 8-10. Up-to congestion transactions by interface pricing point for 2012 are shown in Table 8-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Market are shown in Table 8-12 and Table 8-14, while gross import up-to congestion transactions are show in Table 8-13 and gross export up-to congestion transactions are shown in Table 8-15.

In the Day-Ahead Energy Market, for 2012, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for real-time transactions.[26] The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 71.3 percent of the total net exports: PJM/SouthEXP with 43.2 percent, PJM/Northwest[27] with 16.6 percent and PJM/PJM/Ontario Independent Electricity System Operator (IMO) with 11.6 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 8.1 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interface pricing points had net imports, with three importing interface pricing points accounting for 78.0 percent of the total net imports: PJM/SouthIMP with 30.3 percent, PJM/Ohio Valley Electric Corporation (OVEC) with 24.5 percent, and PJM/MISO with 23.1 percent of the net import volume.

In the Day-Ahead Market, for 2012, up-to congestion transactions had net exports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing

26 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

27 The Northwest interface pricing point is assigned to external energy transactions that source or sink in balancing authorities located primarily in the Northwest United States and the contiguous region of Canada, and which are not balancing authorities within MISO. Many balancing authorities located in the Western Interconnection receive the Northwest interface pricing point because the DC Tie lines that connect the Eastern Interconnection with the Western Interconnection are located in the Northwest United States.

points for up-to congestion transactions accounted for 65.6 percent of the total net up-to congestion exports: PJM/SouthEXP with 49.1 percent and PJM/Ontario Independent Electricity System Operator (IMO) with 16.5 percent of the net export up-to congestion volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 4.2 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 4.2 percent. The PJM/NYIS and the PJM/LINDEN interface pricing points had net imports in the Day-Ahead Energy Market). Seven PJM interface pricing points had net up-to congestion imports, with two importing interface pricing points accounting for 60.0 percent of the total net up-to congestion imports: PJM/MISO with 36.1 percent and PJM/NYIS with 23.9 percent of the net import volume.[28]

Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	(1,019.1)	(410.0)	(868.4)	(952.1)	(919.2)	(584.3)	(511.5)	(161.3)	(381.0)	(274.7)	54.4	(59.1)	(6,086.2)
LINDENVFT	9.2	(51.2)	23.5	74.6	97.9	77.2	113.1	29.3	12.3	(86.6)	5.7	(45.1)	259.9
MISO	1,268.5	1,277.6	1,419.8	1,454.3	1,351.1	782.5	384.0	81.6	527.4	389.1	180.5	158.6	9,275.0
NEPTUNE	(891.7)	(837.7)	(870.3)	(492.9)	(436.7)	(181.7)	(32.0)	(36.6)	(116.9)	(75.6)	40.5	(309.2)	(4,240.8)
NIPSCO	(47.9)	(33.1)	(630.3)	(902.3)	(479.9)	(435.1)	(238.4)	(374.2)	(495.0)	(372.9)	(558.8)	(762.2)	(5,330.2)
NORTHWEST	(524.9)	(370.7)	(543.2)	(751.2)	(644.5)	(750.1)	(776.1)	(880.8)	(770.4)	(1,126.1)	(835.2)	(750.9)	(8,724.0)
NYIS	(35.0)	300.8	573.1	528.3	1,717.1	882.6	231.6	40.2	78.7	(67.9)	(403.0)	(376.6)	3,469.8
OVEC	1,236.4	779.2	1,898.6	1,205.3	3,017.4	1,284.3	894.6	181.9	(271.9)	(564.3)	(74.0)	224.9	9,812.5
SOUTHIMP	2,041.5	2,471.4	2,283.8	2,888.6	3,375.8	2,915.1	3,635.1	3,249.3	2,718.9	3,106.1	1,661.2	1,194.4	31,541.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	27.3	204.2	0.0	0.0	0.0	0.0	231.4
DUKIMP	3.9	12.2	3.5	1.6	4.0	1.0	8.6	78.8	3.6	11.2	2.9	6.5	137.7
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,014.4	1,150.3	901.7	625.8	678.0	343.7	332.4	8,729.3
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	1,087.6	387.9	341.4	10,281.9
SOUTHIMP	777.6	801.7	851.2	1,128.0	1,461.1	1,056.9	1,240.2	1,026.3	1,047.5	1,329.3	926.6	514.1	12,160.7
SOUTHEXP	(3,884.4)	(4,089.1)	(3,761.8)	(4,557.5)	(4,378.1)	(3,848.9)	(4,348.1)	(3,478.4)	(3,182.3)	(3,623.9)	(1,784.8)	(1,588.5)	(42,525.7)
CPLEEXP	(46.7)	(19.8)	(24.9)	(30.3)	(15.7)	(23.5)	(36.0)	(21.1)	(27.2)	(32.7)	(23.0)	(43.6)	(344.6)
DUKEXP	(1.8)	(27.4)	(13.0)	(7.6)	(0.8)	0.0	(5.9)	(20.0)	0.0	0.0	(1.9)	0.0	(78.3)
NCMPAEXP	(0.1)	(0.1)	0.0	(0.5)	(0.8)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(3.9)
SOUTHEAST	(530.7)	(546.3)	(488.7)	(588.0)	(566.5)	(334.4)	(287.6)	(166.4)	(124.7)	(252.2)	(47.8)	(66.5)	(3,999.8)
SOUTHWEST	(1,146.0)	(1,425.1)	(912.1)	(1,485.4)	(1,504.2)	(1,251.0)	(1,871.3)	(1,647.9)	(1,581.1)	(1,407.0)	(493.3)	(661.7)	(15,386.1)
SOUTHEXP	(2,159.1)	(2,070.5)	(2,323.0)	(2,445.7)	(2,290.0)	(2,239.7)	(2,146.9)	(1,622.6)	(1,448.9)	(1,931.7)	(1,218.5)	(816.3)	(22,713.0)
Total	(1,847.5)	(962.7)	(475.1)	(1,505.0)	2,700.9	141.5	(647.7)	(1,349.0)	(1,880.2)	(2,696.6)	(1,713.4)	(2,313.6)	(12,548.4)

28 In the Day-Ahead Market, five PJM interface pricing points (PJM/CPLE, PJM/DUKIMP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

Table 8-11 Up-to Congestion scheduled net interchange volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	(1,104.0)	(559.2)	(981.0)	(1,123.5)	(1,084.7)	(696.5)	(637.1)	(296.2)	(426.3)	(361.6)	(71.1)	(95.5)	(7,436.7)
LINDENVFT	19.4	(49.0)	30.8	75.3	68.6	76.0	102.7	24.8	14.8	(106.5)	5.7	(41.8)	220.8
MISO	1,777.3	1,735.2	1,436.5	1,856.8	1,658.4	1,122.6	1,138.6	653.8	982.7	1,106.0	494.8	648.3	14,610.9
NEPTUNE	(466.5)	(481.8)	(555.8)	(332.9)	(294.0)	(181.7)	(22.7)	237.9	127.4	(5.1)	150.3	(46.5)	(1,871.6)
NIPSCO	(47.9)	(33.1)	(630.3)	(902.3)	(479.9)	(435.1)	(238.4)	(374.2)	(495.0)	(372.9)	(558.8)	(762.2)	(5,330.2)
NORTHWEST	(39.2)	83.5	(113.9)	(364.6)	(162.4)	(287.6)	(305.4)	(408.1)	(310.8)	(645.6)	(366.5)	(267.3)	(3,188.0)
NYIS	710.1	872.0	911.2	767.0	1,905.9	1,342.3	911.9	736.5	653.5	495.0	177.4	211.7	9,694.6
OVEC	690.8	257.9	1,459.4	732.7	2,391.5	731.3	254.4	(367.0)	(651.3)	(1,174.7)	(800.9)	(359.9)	3,164.3
SOUTHIMP	1,727.7	2,134.2	2,131.7	2,542.2	2,960.4	2,469.4	3,234.4	2,603.1	2,350.8	2,638.3	1,331.5	984.6	27,108.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,013.7	1,150.3	901.7	625.6	674.4	343.7	332.4	8,724.7
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	1,087.6	387.9	341.4	10,281.9
SOUTHIMP	467.7	476.7	702.6	783.3	1,049.8	612.9	875.4	663.1	683.1	876.3	599.9	310.8	8,101.5
SOUTHEXP	(3,787.2)	(3,977.3)	(3,660.3)	(4,474.2)	(4,293.4)	(3,776.5)	(4,260.5)	(3,397.6)	(3,118.4)	(3,553.1)	(1,717.1)	(1,504.9)	(41,520.7)
CPLEEXP	0.0	0.0	0.0	(1.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.2)
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(530.7)	(546.3)	(488.7)	(588.0)	(566.5)	(334.4)	(287.6)	(166.4)	(124.7)	(252.2)	(47.8)	(66.5)	(3,999.8)
SOUTHWEST	(1,146.0)	(1,425.1)	(912.1)	(1,485.4)	(1,504.2)	(1,251.0)	(1,871.3)	(1,647.9)	(1,581.1)	(1,407.0)	(493.3)	(661.7)	(15,386.1)
SOUTHEXP	(2,110.6)	(2,005.9)	(2,259.5)	(2,399.6)	(2,222.6)	(2,191.2)	(2,101.6)	(1,583.3)	(1,412.6)	(1,893.9)	(1,176.0)	(776.7)	(22,133.6)
Total Interfaces	(519.6)	(17.7)	28.2	(1,223.6)	2,670.4	364.2	177.9	(586.8)	(872.8)	(1,980.3)	(1,354.7)	(1,233.5)	(4,548.3)
INTERNAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14,482.7	21,958.1	36,440.8
Total	(519.6)	(17.7)	28.2	(1,223.6)	2,670.4	364.2	177.9	(586.8)	(872.8)	(1,980.3)	13,128.0	20,724.6	31,892.5

Table 8-12 Day-Ahead scheduled gross import volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	545.7	587.1	505.6	549.9	792.8	623.9	610.5	804.1	524.1	572.5	405.3	329.2	6,850.7
LINDENVFT	350.2	372.2	459.9	514.9	577.6	520.9	627.9	508.6	477.9	519.1	17.6	159.5	5,106.4
MISO	4,021.4	3,236.4	3,339.4	3,847.6	3,669.5	2,551.1	2,146.4	1,882.8	2,373.8	2,212.7	992.5	819.9	31,093.6
NEPTUNE	0.0	0.0	0.0	0.0	13.4	86.9	250.9	436.3	418.9	172.6	184.2	156.0	1,719.2
NIPSCO	456.4	514.0	364.9	292.8	235.4	259.8	302.7	312.2	339.0	240.4	65.0	39.4	3,422.0
NORTHWEST	769.8	664.5	502.0	432.2	596.9	442.7	306.7	354.9	370.6	280.3	208.7	233.3	5,162.7
NYIS	1,592.7	1,890.4	2,212.4	1,963.8	3,173.2	2,504.8	2,037.3	2,025.9	1,973.7	2,052.3	1,271.8	1,464.8	24,163.2
OVEC	5,409.6	4,917.3	5,435.3	6,522.2	7,231.1	4,851.3	5,391.6	5,611.7	4,688.1	5,112.1	3,754.4	2,657.8	61,582.4
SOUTHIMP	2,041.5	2,471.4	2,283.8	2,888.6	3,375.8	2,915.1	3,635.1	3,249.3	2,718.9	3,106.1	1,661.2	1,194.4	31,541.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	27.3	204.2	0.0	0.0	0.0	0.0	231.4
DUKIMP	3.9	12.2	3.5	1.6	4.0	1.0	8.6	78.8	3.6	11.2	2.9	6.5	137.7
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,014.4	1,150.3	901.7	625.8	678.0	343.7	332.4	8,729.3
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	1,087.6	387.9	341.4	10,281.9
SOUTHIMP	777.6	801.7	851.2	1,128.0	1,461.1	1,056.9	1,240.2	1,026.3	1,047.5	1,329.3	926.6	514.1	12,160.7
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	15,187.4	14,653.3	15,103.4	17,011.9	19,665.8	14,756.4	15,309.1	15,185.8	13,885.1	14,268.1	8,560.7	7,054.4	170,641.5

Table 8-13 Up-to Congestion scheduled gross import volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	460.9	437.9	393.0	378.5	627.2	511.7	484.9	669.2	478.7	485.5	279.7	292.8	5,500.2
LINDENVFT	350.2	370.9	458.2	507.2	544.9	514.5	609.0	493.8	473.0	495.1	17.6	159.1	4,993.5
MISO	3,891.7	3,083.1	3,111.6	3,714.3	3,504.7	2,548.7	2,144.0	1,880.1	2,364.8	2,206.9	982.9	818.6	30,251.3
NEPTUNE	0.0	0.0	0.0	0.0	13.4	86.9	250.9	436.3	418.9	172.6	184.2	156.0	1,719.2
NIPSCO	456.4	514.0	364.9	292.8	235.4	259.8	302.7	312.2	339.0	240.4	65.0	39.4	3,422.0
NORTHWEST	769.8	664.5	502.0	432.2	596.9	442.7	306.7	354.9	370.6	280.3	208.7	233.3	5,162.7
NYIS	1,233.0	1,358.8	1,484.0	1,316.4	2,517.9	1,793.8	1,266.2	1,274.1	1,294.3	1,341.1	707.2	814.1	16,400.9
OVEC	4,838.3	4,372.6	4,972.8	6,030.9	6,585.2	4,298.4	4,751.4	5,044.4	4,291.1	4,501.6	3,027.5	2,073.0	54,787.0
SOUTHIMP	1,727.7	2,134.2	2,131.7	2,542.2	2,960.4	2,469.4	3,234.4	2,603.1	2,350.8	2,638.3	1,331.5	984.6	27,108.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,013.7	1,150.3	901.7	625.6	674.4	343.7	332.4	8,724.7
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	1,087.6	387.9	341.4	10,281.9
SOUTHIMP	467.7	476.7	702.6	783.3	1,049.8	612.9	875.4	663.1	683.1	876.3	599.9	310.8	8,101.5
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	13,728.0	12,936.0	13,418.2	15,214.5	17,586.0	12,925.9	13,350.2	13,068.1	12,381.2	12,361.9	6,804.3	5,570.9	149,345.1

Table 8-14 Day-Ahead scheduled gross export volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	1,564.8	997.1	1,374.0	1,502.0	1,711.9	1,208.3	1,122.0	965.4	905.1	847.2	350.8	388.3	12,936.9
LINDENVFT	341.0	423.5	436.3	440.3	479.7	443.7	514.9	479.3	465.6	605.7	11.9	204.5	4,846.4
MISO	2,753.0	1,958.8	1,919.6	2,393.3	2,318.5	1,768.5	1,762.3	1,801.2	1,846.4	1,823.6	812.0	661.4	21,818.6
NEPTUNE	891.7	837.7	870.3	492.9	450.2	268.6	282.9	472.9	535.8	248.1	143.7	465.3	5,960.1
NIPSCO	504.3	547.1	995.3	1,195.1	715.3	694.8	541.1	686.4	834.1	613.3	623.8	801.6	8,752.2
NORTHWEST	1,294.7	1,035.1	1,045.3	1,183.3	1,241.3	1,192.8	1,082.9	1,235.7	1,141.1	1,406.4	1,043.9	984.2	13,886.7
NYIS	1,627.7	1,589.6	1,639.4	1,435.5	1,456.1	1,622.2	1,805.7	1,985.7	1,895.0	2,120.2	1,674.9	1,841.3	20,693.3
OVEC	4,173.2	4,138.0	3,536.6	5,317.0	4,213.8	3,567.0	4,497.0	5,429.8	4,960.0	5,676.4	3,828.4	2,432.8	51,769.9
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	3,884.4	4,089.1	3,761.8	4,557.5	4,378.1	3,848.9	4,348.1	3,478.4	3,182.3	3,623.9	1,784.8	1,588.5	42,525.7
CPLEEXP	46.7	19.8	24.9	30.3	15.7	23.5	36.0	21.1	27.2	32.7	23.0	43.6	344.6
DUKEXP	1.8	27.4	13.0	7.6	0.8	0.0	5.9	20.0	0.0	0.0	1.9	0.0	78.3
NCMPAEXP	0.1	0.1	0.0	0.5	0.8	0.4	0.4	0.4	0.4	0.3	0.3	0.3	3.9
SOUTHEAST	530.7	546.3	488.7	588.0	566.5	334.4	287.6	166.4	124.7	252.2	47.8	66.5	3,999.8
SOUTHWEST	1,146.0	1,425.1	912.1	1,485.4	1,504.2	1,251.0	1,871.3	1,647.9	1,581.1	1,407.0	493.3	661.7	15,386.1
SOUTHEXP	2,159.1	2,070.5	2,323.0	2,445.7	2,290.0	2,239.7	2,146.9	1,622.6	1,448.9	1,931.7	1,218.5	816.3	22,713.0
Total	17,034.9	15,616.0	15,578.5	18,516.9	16,964.9	14,614.9	15,956.8	16,534.8	15,765.3	16,964.8	10,274.1	9,368.0	183,189.9

Table 8-15 Up-to Congestion scheduled gross export volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	1,564.8	997.1	1,374.0	1,502.0	1,711.9	1,208.3	1,122.0	965.4	905.1	847.2	350.8	388.3	12,936.9
LINDENVFT	330.8	419.9	427.4	431.9	476.3	438.5	506.3	469.0	458.2	601.7	11.9	200.9	4,772.7
MISO	2,114.4	1,347.8	1,675.1	1,857.6	1,846.3	1,426.0	1,005.4	1,226.3	1,382.2	1,100.9	488.1	170.2	15,640.4
NEPTUNE	466.5	481.8	555.8	332.9	307.4	268.6	273.6	198.4	291.5	177.7	33.9	202.6	3,590.8
NIPSCO	504.3	547.1	995.3	1,195.1	715.3	694.8	541.1	686.4	834.1	613.3	623.8	801.6	8,752.2
NORTHWEST	809.1	581.0	615.9	796.8	759.3	730.3	612.2	763.0	681.5	925.9	575.2	500.6	8,350.7
NYIS	522.9	486.9	572.8	549.4	612.0	451.5	354.3	537.6	640.8	846.0	529.8	602.3	6,706.2
OVEC	4,147.5	4,114.8	3,513.3	5,298.2	4,193.7	3,567.0	4,497.0	5,411.4	4,942.4	5,676.4	3,828.4	2,432.8	51,622.8
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	3,787.2	3,977.3	3,660.3	4,474.2	4,293.4	3,776.5	4,260.5	3,397.6	3,118.4	3,553.1	1,717.1	1,504.9	41,520.7
CPLEEXP	0.0	0.0	0.0	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	530.7	546.3	488.7	588.0	566.5	334.4	287.6	166.4	124.7	252.2	47.8	66.5	3,999.8
SOUTHWEST	1,146.0	1,425.1	912.1	1,485.4	1,504.2	1,251.0	1,871.3	1,647.9	1,581.1	1,407.0	493.3	661.7	15,386.1
SOUTHEXP	2,110.6	2,005.9	2,259.5	2,399.6	2,222.6	2,191.2	2,101.6	1,583.3	1,412.6	1,893.9	1,176.0	776.7	22,133.6
Total	14,247.6	12,953.7	13,390.0	16,438.1	14,915.6	12,561.6	13,172.3	13,654.9	13,254.1	14,342.2	8,159.0	6,804.4	153,893.4

Table 8-16 Active interfaces: 2012[29]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

29 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of December 31, 2012, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.

Figure 8-3 PJM's footprint and its external interfaces

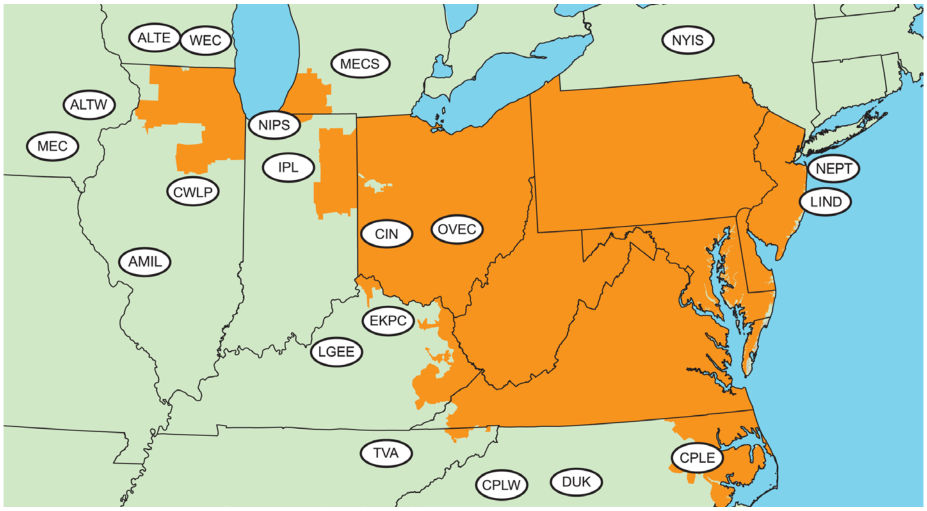


Table 8-17 Active pricing points: 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

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.

Loop flows can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also exist as a result of transactions within a market based area in the absence of an explicit agreement to price congestion. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

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. Loop flows also have poorly understood impacts on non-market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear.

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both MISO's border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows).

If PJM net actual interface flows were close to net scheduled interface flows, on average for 2012, it would not necessarily mean that there was no loop flow. Loop flows are measured at individual interfaces. There can be no difference between scheduled and actual flows for PJM and still be significant differences between scheduled and actual flows for specific individual interfaces. From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous balancing authorities.

In 2012, net scheduled interchange was 898 GWh and net actual interchange was 672 GWh, a difference of 226 GWh, compared to net scheduled interchange of -7,072 GWh and net actual interchange of -7,576 GWh, a difference of 504 GWh in 2011.[30] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[31]

Table 8-18 Net scheduled and actual PJM flows by interface (GWh): 2012

	Actual	Net Scheduled	Difference (GWh)
CPLE	7,954	(350)	8,304
CPLW	(1,500)	0	(1,500)
DUK	(717)	371	(1,089)
EKPC	2,455	(625)	3,080
LGEE	1,370	2,687	(1,316)
MEC	(2,627)	(5,382)	2,756
MISO	(15,262)	(2,663)	(12,599)
ALTE	(5,869)	(6,720)	850
ALTW	(2,497)	(282)	(2,214)
AMIL	11,190	1,078	10,112
CIN	(6,112)	1,308	(7,420)
CWLP	(537)	0	(537)
IPL	669	(1,467)	2,136
MECS	(10,337)	5,682	(16,019)
NIPS	(6,375)	(172)	(6,203)
WEC	4,607	(2,089)	6,696
NYISO	(8,664)	(8,574)	(90)
LIND	(636)	(636)	0
NEPT	(2,253)	(2,253)	0
NYIS	(5,774)	(5,685)	(90)
OVEC	11,578	8,926	2,652
TVA	6,084	6,508	(424)
Total	672	898	(226)

30 The "Net Scheduled" values shown in Table 8-18 include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in this table does not match the interchange values shown in Table 8-1 through Table 8-6.

31 See PJM. "M-12: Balancing Operations", Revision 23 (November 16, 2011).

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.[32] 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 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 8-19 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, as opposed to the individual pricing points, provides some insight on 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 (13,191 GWh of imports at the SouthIMP Interface Pricing Point) would best be 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 14,604 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 did 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 8-19 Net scheduled and actual PJM flows by interface pricing point (GWh): 2012

	Actual	Net Scheduled	Difference (GWh)
IMO	0	5,881	(5,881)
LINDENVFT	(636)	(636)	0
MISO	(12,806)	(20,031)	7,225
NEPTUNE	(2,253)	(2,253)	0
NORTHWEST	(2,627)	(110)	(2,517)
NYIS	(5,774)	(5,484)	(290)
OVEC	11,578	8,926	2,652
SOUTHIMP	13,191	18,533	(5,343)
CPLEIMP	0	535	(535)
DUKIMP	0	1,077	(1,077)
NCMPAIMP	0	348	(348)
SOUTHWEST	0	0	0
SOUTHIMP	13,191	16,573	(3,383)
SOUTHEXP	0	(3,929)	3,929
CPLEEXP	0	(367)	367
DUKEXP	0	(1,599)	1,599
NCMPAEXP	0	(5)	5
SOUTHWEST	0	(42)	42
SOUTHEXP	0	(1,916)	1,916
Total	672	898	(226)

Table 8-20 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points

32 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) (Accessed January 16, 2013)

based on the quantities of scheduled interchange where transactions from the Ontario Independent Electricity System Operator (IMO) entered the PJM Energy Market.

Table 8-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): 2012

	Actual	Net Scheduled	Difference (GWh)
LINDENVFT	(636)	(636)	0
MISO	(12,806)	(14,129)	1,323
NEPTUNE	(2,253)	(2,253)	0
NORTHWEST	(2,627)	(110)	(2,517)
NYIS	(5,774)	(5,505)	(270)
OVEC	11,578	8,926	2,652
SOUTHIMP	13,191	18,533	(5,343)
CPLEIMP	0	535	(535)
DUKIMP	0	1,077	(1,077)
NCMPAIMP	0	348	(348)
SOUTHWEST	0	0	0
SOUTHIMP	13,191	16,573	(3,383)
SOUTHEXP	0	(3,929)	3,929
CPLEEXP	0	(367)	367
DUKEXP	0	(1,599)	1,599
NCMPAEXP	0	(5)	5
SOUTHWEST	0	(42)	42
SOUTHEXP	0	(1,916)	1,916
Total	672	898	(226)

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 8-21 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 8-21 shows that 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 for which the actual flows would enter the PJM Energy Market at the southern region, and thus were assigned the SouthIMP Interface Pricing point (3,237 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 (2,907 GWh).

Table 8-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): 2012

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(5,869)	(6,720)	850	IPL		669	(1,467)	2,136
	MISO	(5,869)	(6,718)	848		IMO	0	897	(897)
	NORTHWEST	0	(7)	7		MISO	669	(2,353)	3,022
	SOUTHEXP	0	(0)	0		NORTHWEST	0	(72)	72
	SOUTHIMP	0	5	(5)		SOUTHEXP	0	(6)	6
ALTW		(2,497)	(282)	(2,214)		SOUTHIMP	0	66	(66)
	MISO	(2,497)	(259)	(2,238)	LGEE		1,370	2,687	(1,316)
	NORTHWEST	0	(23)	23		SOUTHEXP	0	(149)	149
AMIL		11,190	1,078	10,112		SOUTHIMP	1,370	2,836	(1,465)
	IMO	0	(0)	0	LIND		(636)	(636)	0
	MISO	11,190	890	10,300		LINDENVFT	(636)	(636)	0
	NORTHWEST	0	(0)	0	MEC		(2,627)	(5,382)	2,756
	SOUTHEXP	0	(0)	0		IMO	0	0	(0)
	SOUTHIMP	0	230	(230)		MISO	0	(5,600)	5,600
	SOUTHWEST	0	(41)	41		NORTHWEST	(2,627)	4	(2,630)
CIN		(6,112)	1,308	(7,420)		SOUTHIMP	0	214	(214)
	IMO	0	811	(811)	MECS		(10,337)	5,682	(16,019)
	MISO	(6,112)	(2,907)	(3,205)		IMO	0	4,192	(4,192)
	NORTHWEST	0	(10)	10		MISO	(10,337)	(712)	(9,625)
	NYIS	0	180	(180)		NORTHWEST	0	(0)	0
	SOUTHEXP	0	(4)	4		NYIS	0	0	(0)
	SOUTHIMP	0	3,237	(3,237)		SOUTHIMP	0	2,202	(2,202)
CPLE		7,954	(350)	8,304	NEPT		(2,253)	(2,253)	0
	CPLEEXP	0	(367)	367		NEPTUNE	(2,253)	(2,253)	0
	CPLEIMP	0	535	(535)	NIPS		(6,375)	(172)	(6,203)
	DUKIMP	0	0	(0)		IMO	0	1	(1)
	SOUTHEXP	0	(30)	30		MISO	(6,375)	(575)	(5,800)
	SOUTHIMP	7,954	(489)	8,443		NORTHWEST	0	(0)	0
CPLW		(1,500)	0	(1,500)		SOUTHIMP	0	402	(402)
	SOUTHIMP	(1,500)	0	(1,500)	NYIS		(5,774)	(5,685)	(90)
CWLP		(537)	0	(537)		IMO	0	(21)	21
	MISO	(537)	0	(537)		NYIS	(5,774)	(5,664)	(110)
DUK		(717)	371	(1,089)	OVEC		11,578	8,926	2,652
	DUKEXP	0	(1,599)	1,599		OVEC	11,578	8,926	2,652
	DUKIMP	0	1,073	(1,073)	TVA		6,084	6,508	(424)
	NCMPAEXP	0	(5)	5		DUKIMP	0	4	(4)
	NCMPAIMP	0	348	(348)		SOUTHEXP	0	(358)	358
	SOUTHEXP	0	(243)	243		SOUTHIMP	6,084	6,862	(778)
	SOUTHIMP	(717)	798	(1,515)		SOUTHWEST	0	(0)	0
	SOUTHWEST	0	(0)	0	WEC		4,607	(2,089)	6,696
EKPC		2,455	(625)	3,080		MISO	4,607	(2,099)	6,705
	MISO	2,455	301	2,154		NORTHWEST	0	(1)	1
	SOUTHEXP	0	(1,126)	1,126		SOUTHEXP	0	(0)	0
	SOUTHIMP	0	200	(200)		SOUTHIMP	0	11	(11)
					Total		672	898	(226)

Table 8-22 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 8-22 shows that 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 (4,192 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 (21 GWh).

Table 8-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): 2012

Interface pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(367)	367	NYIS		(5,774)	(5,484)	(290)
	CPLE	0	(367)	367		CIN	0	180	(180)
CPLEIMP		0	535	(535)		MECS	0	0	(0)
	CPLE	0	535	(535)		NYIS	(5,774)	(5,664)	(110)
DUKEXP		0	(1,599)	1,599	OVEC		11,578	8,926	2,652
	DUK	0	(1,599)	1,599		OVEC	11,578	8,926	2,652
DUKIMP		0	1,077	(1,077)	SOUTHEXP		0	(1,916)	1,916
	CPLE	0	0	(0)		ALTE	0	(0)	0
	DUK	0	1,073	(1,073)		AMIL	0	(0)	0
	TVA	0	4	(4)		CIN	0	(4)	4
IMO		0	5,881	(5,881)		CPLE	0	(30)	30
	AMIL	0	(0)	0		DUK	0	(243)	243
	CIN	0	811	(811)		EKPC	0	(1,126)	1,126
	IPL	0	897	(897)		IPL	0	(6)	6
	MEC	0	0	(0)		LGEE	0	(149)	149
	MECS	0	4,192	(4,192)		TVA	0	(358)	358
	NIPS	0	1	(1)		WEC	0	(0)	0
	NYIS	0	(21)	21	SOUTHIMP		13,191	16,573	(3,383)
LINDENVFT		(636)	(636)	0		ALTE	0	5	(5)
	LIND	(636)	(636)	0		AMIL	0	230	(230)
MISO		(12,806)	(20,031)	7,225		CIN	0	3,237	(3,237)
	ALTE	(5,869)	(6,718)	848		CPLE	7,954	(489)	8,443
	ALTW	(2,497)	(259)	(2,238)		CPLW	(1,500)	0	(1,500)
	AMIL	11,190	890	10,300		DUK	(717)	798	(1,515)
	CIN	(6,112)	(2,907)	(3,205)		EKPC	0	200	(200)
	CWLP	(537)	0	(537)		IPL	0	66	(66)
	EKPC	2,455	301	2,154		LGEE	1,370	2,836	(1,465)
	IPL	669	(2,353)	3,022		MEC	0	214	(214)
	MEC	0	(5,600)	5,600		MECS	0	2,202	(2,202)
	MECS	(10,337)	(712)	(9,625)		NIPS	0	402	(402)
	NIPS	(6,375)	(575)	(5,800)		TVA	6,084	6,862	(778)
	WEC	4,607	(2,099)	6,705		WEC	0	11	(11)
NCMPAEXP		0	(5)	5	SOUTHWEST		0	(42)	42
	DUK	0	(5)	5		AMIL	0	(41)	41
NCMPAIMP		0	348	(348)		DUK	0	(0)	0
	DUK	0	348	(348)		TVA	0	(0)	0
NEPTUNE		(2,253)	(2,253)	0	Total		672	898	(226)
	NEPT	(2,253)	(2,253)	0					
NORTHWEST		(2,627)	(110)	(2,517)					
	ALTE	0	(7)	7					
	ALTW	0	(23)	23					
	AMIL	0	(0)	0					
	CIN	0	(10)	10					
	IPL	0	(72)	72					
	MEC	(2,627)	4	(2,630)					
	MECS	0	(0)	0					
	NIPS	0	(0)	0					
	WEC	0	(1)	1					

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[33] 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.[34]

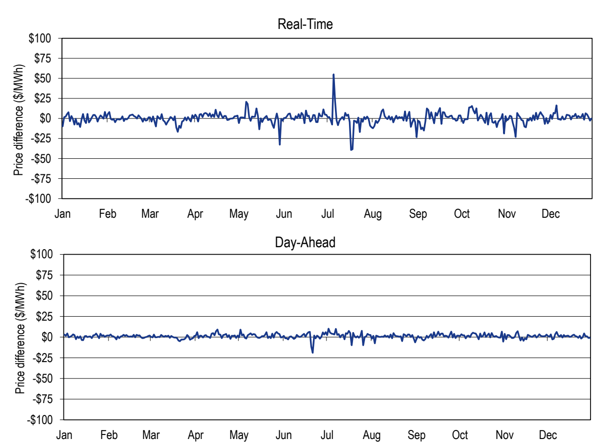
Real-Time and Day-Ahead PJM/MISO Interface Prices

In 2012, the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average hourly flow. In 2012, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $26.95 while the MISO LMP at the border was $27.15, a difference of $0.20. While the average hourly LMP difference at the PJM/MISO border was only $0.20, the average of the absolute values of the hourly differences was $8.93. The average hourly flow during 2012 was -1,737 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.) However, the direction of flows was consistent with price differentials in only 47 percent of hours in 2012. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $10.36. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $7.83. In 2012, 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 $9.80. 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 $21.11. 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 $17.32. 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 $6.92.

In 2012, the day-ahead PJM average hourly LMP at the PJM/MISO border was $26.62 while the MISO LMP at the border was $27.72, a difference of $1.10.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-4). 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 8-6).

Figure 8-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): 2012



33 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed January 16, 2013). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

34 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010). (Accessed January 16, 2013)

Distribution of Economic and Uneconomic Hourly Flows

During 2012, the direction of hourly energy flows was consistent with PJM and MISO Interface Price differentials in 4,104 hours (46.7 percent of all hours), and was inconsistent with price differentials in 4,680 hours (53.3 percent of all hours). Table 8-23 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 4,680 hours where flows were uneconomic, 3,981 of those hours (85.1 percent) had a price difference greater than or equal to $1.00 and 1,656 of all uneconomic hours (35.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $949.61. Of the 4,104 hours where flows were economic, 3,499 of those hours (85.3 percent) had a price difference greater than or equal to $1.00 and 1,989 of all economic hours (48.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $440.39.

Table 8-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: 2012

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	4,680	100.0%	4,104	100.0%
$1.00	3,981	85.1%	3,499	85.3%
$5.00	1,656	35.4%	1,989	48.5%
$10.00	714	15.3%	1,118	27.2%
$15.00	424	9.1%	696	17.0%
$20.00	308	6.6%	495	12.1%
$25.00	226	4.8%	383	9.3%
$50.00	89	1.9%	140	3.4%
$75.00	39	0.8%	72	1.8%
$100.00	26	0.6%	44	1.1%
$200.00	7	0.1%	6	0.1%
$300.00	2	0.0%	3	0.1%
$400.00	2	0.0%	2	0.0%
$500.00	1	0.0%	0	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.

The NYISO Locational Based Marginal Pricing (LBMP) calculation methodology differs from the PJM LMP calculation methodology. PJM uses real-time operating conditions and real-time energy flows to calculate LMPs. The NYISO software calculates LBMP using expected flows derived from Real-Time Commitment (RTC) software based on the assumption that phase angle regulators (PARs) can be set such that the average actual flows match the expected interchange on PAR controlled lines. The NYISO also calculates the flows across their free-flowing A/C tie lines using current network configurations for the purposes of calculating line loadings and the resulting congestion costs. 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. This Keystone proxy bus is an aggregate pricing point, representing the price of energy between PJM and the NYISO, with a 40 percent weighting on the Branchburg to Ramapo line and a 60 percent weighting on the remaining free flowing ties. PJM calculates the NYISO Interface Price using an 80 percent weighting on the Roseton 345 KV bus, and a 20 percent weighting on the Dunkirk 115 KV bus.

Effective June 27, 2012, the NYISO implemented 15-minute scheduling of external energy transactions between the NYISO and PJM.[35] However, the timing requirements for market participants to submit external energy transactions did not change as a result of the new process. All transactions must continue to be submitted to the NYISO 75 minutes prior to the operating hour, and the NYISO's RTC application commits (or decommits) external energy transactions for each 15-minute interval of the operating hour. While this modification provides a better economic mix of generation and interchange transactions during the operating hour, it does not allow market participants to react to real-time pricing, as all transactions must be submitted in advance of real-time price signals.

35 See *New York Independent System Operator, Inc.* Docket No. ER11-2547-001 (June 6, 2012).

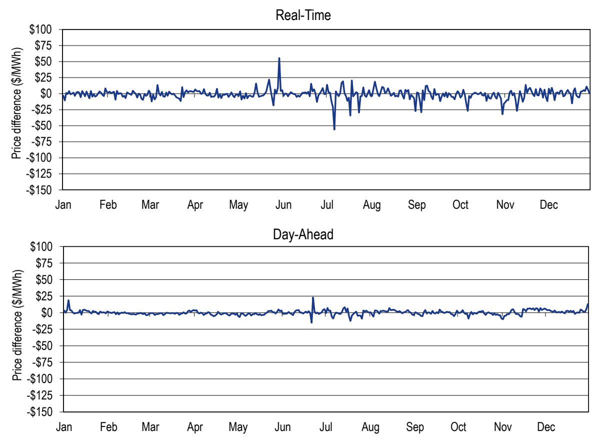
Real-Time and Day-Ahead PJM/NYISO Interface Prices

In 2012, 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 2012, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. In 2012, the PJM average hourly LMP at the PJM/NYISO border was $34.09 while the NYISO LMP at the border was $33.15, a difference of $0.94. While the average hourly LMP difference at the PJM/NYISO border was only $0.94, the average of the absolute value of the hourly difference was $9.69. The average hourly flow during 2012 was -657 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.) However, the direction of flows was consistent with price differentials in only 52.8 percent of the hours in 2012. In 2012, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $9.11. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $10.25. In 2012, 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 $8.49. 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 $14.80. 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 $11.61. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from PJM to NYISO, the average price difference was $9.94.

In 2012, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $33.68 while the NYIS LMP at the border was $33.79, a difference of $0.11.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-5). 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 8-6).

Figure 8-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): 2012



Distribution of Economic and Uneconomic Hourly Flows

During 2012, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 4,641 (52.8 percent of all hours), and was inconsistent with price differences in 4,143 hours (47.2 percent of all hours). Table 8-24 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 4,143 hours where flows were uneconomic, 3,591 of those hours (86.7 percent) had a price difference greater than or equal to $1.00 and 1,952 of all uneconomic hours (47.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $389.38. Of the 4,641 hours where flows were economic, 4,085 of those hours (88.0 percent) had a price difference greater than or equal to $1.00 and 2,027 of all economic hours (43.7 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $597.32.

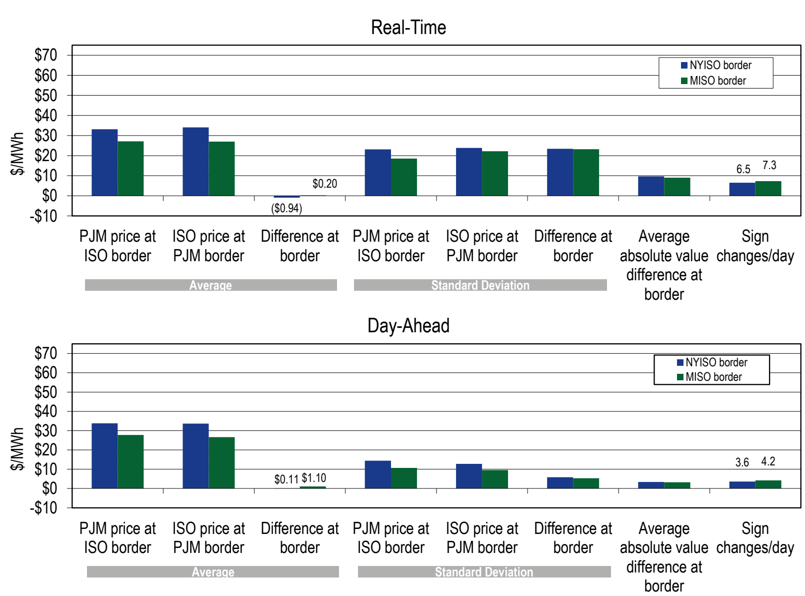
Table 8-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: 2012

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	4,143	100.0%	4,641	100.0%
$1.00	3,591	86.7%	4,085	88.0%
$5.00	1,952	47.1%	2,027	43.7%
$10.00	1,028	24.8%	943	20.3%
$15.00	690	16.7%	548	11.8%
$20.00	479	11.6%	376	8.1%
$25.00	355	8.6%	285	6.1%
$50.00	162	3.9%	115	2.5%
$75.00	89	2.1%	62	1.3%
$100.00	42	1.0%	41	0.9%
$200.00	4	0.1%	13	0.3%
$300.00	1	0.0%	4	0.1%
$400.00	0	0.0%	2	0.0%
$500.00	0	0.0%	1	0.0%

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 8-6, including average prices and measures of variability.

Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: 2012



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 2012, the average hourly difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average hourly flow. In 2012, the PJM average hourly LMP at the Neptune Interface was $34.14 while the NYISO LMP at the Neptune Bus was $43.92, a difference of $9.78.[36] While the average hourly LMP difference at the PJM/Neptune border was $9.78, the average of the absolute value of the hourly difference was $17.07. The average hourly flow during 2012 was -257 MW.[37] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64.5 percent of the hours in 2012. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average hourly price difference was $20.31. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $10.79.

36 In 2012, there were 3,056 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 $32.96 while the NYISO LMP at the Neptune Bus during non-zero flows was $39.70, a difference of $6.74.

37 The average hourly flow during 2012, ignoring hours with no flow, on the Neptune DC Tie line was -393 MW.

Figure 8-7 Neptune hourly average flow: 2012

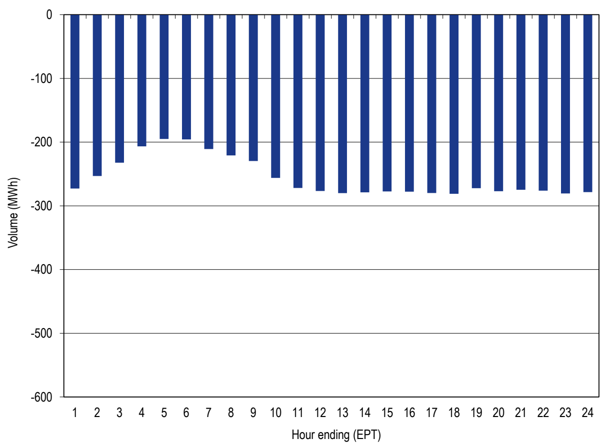
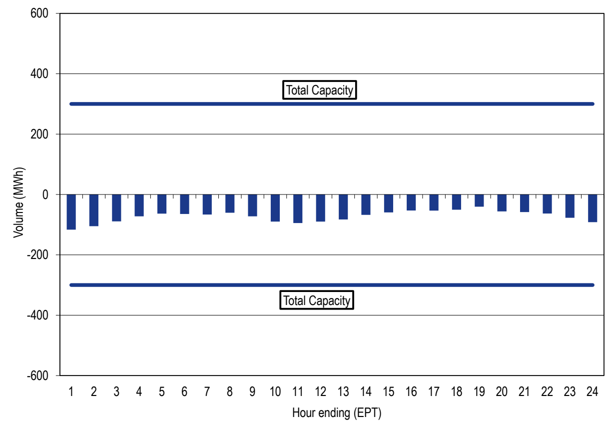


Figure 8-8 Linden hourly average flow: 2012[40]



Linden Variable Frequency Transformer (VFT) Facility

The Linden VFT facility is a 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 2012, the average hourly difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average hourly flow. In 2012, the PJM average hourly LMP at the Linden Interface was $34.70 while the NYISO LMP at the Linden Bus was $37.63, a difference of $2.93.[38] While the average hourly LMP difference at the PJM/Linden border was $2.93, the average of the absolute value of the hourly difference was $12.49. The average hourly flow during 2012 was -72 MW.[39] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 59.5 percent of the hours in 2012. When the NYISO/Linden Interface price was greater than the PJM/LIND Interface price, the average hourly price difference was $12.88. When the PJM/LIND Interface price was greater than the NYISO/ Linden Interface price, the average price difference was $11.92.

Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) line will be 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 will be a submarine AC cable system. While the Hudson DC line will be a bidirectional line, power flows will only be 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). The Hudson DC line is expected to be in service by the end of the second quarter of 2013.

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.

38 In 2012, there were 1,630 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 $34.23 while the NYISO LMP at the Neptune Bus during non-zero flows was $36.61, a difference of $2.38.

39 The average hourly flow during 2012, ignoring hours with no flow, on the Linden VFT line was -89 MW.

40 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.

PJM and MISO Joint Operating Agreement[41]

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.[42]

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.

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 which both have significant impacts. Only RCF's are subject to the market to market congestion management process.

In 2012, 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. 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 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 2012, 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 8-9 shows credits for coordinated congestion management between PJM and MISO.

In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process. The final report, which was completed and distributed on January 20, 2012, showed that both PJM and MISO are conforming to the JOA.[43] The report also provided some potential areas of improvement including improved internal documentation, enhanced transparency, and an increase of knowledge sharing, data exchange and attention to modeling differences.

Generation in one RTO may affect congestion in the other RTO. To ensure that the most economic mix of generation is being utilized to control constraints, it is important to ensure that generators within each RTO are following the dispatch signal. If a generator remains on when the economic signal suggests it should be reduced, or come offline, the output from that generator could contribute to congestion, and may create the need to enter into market to market activity. When this is the case, the generator that is operating uneconomically may create congestion credits to be paid from one RTO

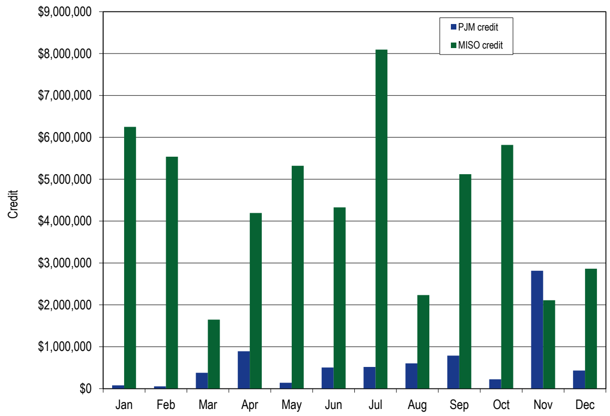
41 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>. (Accessed October 16, 2012)

42 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>.

43 See "Utilicast Final Report - JOA Baseline Review," (January 20, 2012) <http://www.pjm.com/documents/~/media/documents/reports/20120120-utilcast-final-report-joa-baseline-review.ashx> (Accessed January 16, 2013)

to the other. The MMU suggests that the RTOs evaluate whether this is occurring and the appropriate impact on the congestion payments under the JOA.

Figure 8-9 Credits for coordinated congestion management: 2012



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[44]

On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It formalized the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

The PJM/NYISO JOA did not include provisions for market based congestion management or other market to market activity, so, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol.[45] On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that included a draft market to market process.[46] On May 1, 2012, PJM and the NYISO filed a second revision to the JOA that included resolutions to several outstanding issues, present in the December 30, 2011 filing, which they requested additional time to resolve.[47] Some of the resolved issues were how to calculate firm flow entitlements (FFE), how to model external capacity resources in developing FFEs and how to include the Ontario/Michigan PAR operations in the market flow calculation. On September 20, 2012, FERC issued an Order On Compliance Filing, accepting the implementation date of a market to market coordination process to be effective no later than January 15, 2013.[48] The September 20, 2012, Order requires modifications to the JOA to provide for incremental impacts of the Ontario/Michigan PARs when any of the PARs are in service.

In 2012, the MMU protested the Interface Pricing methodology proposed by the NYISO.[49] The MMU filed comments that the method implemented by NYISO failed to address the issues identified by the Commission in its prior orders and leaves in place the potential incentives to inefficient scheduling and gaming that the changes were intended to address. The MMU suggested that if NYISO were to extend their eTag path validation approach, NYISO could ensure that all external energy transactions are scheduled on a market path on which the energy will actually flow and for which the NYISO calculates a price. This approach would substitute a rule that identifies scheduled paths to reject, for the approach that tries to identify, in advance, every possible circuitous path. This method would be entirely consistent with the current NYISO approach, and could provide for accurate transaction pricing and eliminate the pricing incentive for market participants to schedule along inefficient paths of the type which contribute to Lake Erie loop flows.

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

44 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (June 30, 2010) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed January 16, 2013)

45 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.

46 See "Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (December 30, 2011).

47 See "Second Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (May 1, 2012).

48 140 FERC ¶ 61,205 (2012).

49 See "Protest of the Independent Market Monitor for PJM," Docket No(s) ER08-1281-005,-006, -007 and -010 (January 12, 2012).

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 2012, there were no developments. The agreement continued to be in effect in 2012.

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.[50] 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 2012, there were no developments. The agreement remained in effect in 2012.

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.[51]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[52] 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.[53] 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 8-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: 2012

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.11	$31.30	$30.97	$30.97	$0.14	$0.33
PEC	$31.50	$31.53	$30.97	$30.97	$0.53	$0.56
NCMPA	$31.25	$31.25	$30.97	$30.97	$0.28	$0.28

Table 8-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: 2012

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.99	$31.59	$30.66	$30.66	$0.33	$0.93
PEC	$31.46	$31.81	$30.66	$30.66	$0.80	$1.16
NCMPA	$31.26	$31.33	$30.66	$30.66	$0.60	$0.67

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

50 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

51 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 January 16, 2013)

52 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

53 See Docket Nos. ER12-1338-000 and ER12-1343-000.

York and wheeled through New York and New Jersey including lines controlled by PJM.[54] 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.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City. Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2012, PSE&G's revenues were more than its congestion charges by $80,727 after adjustments (revenues were more than its congestion charges by $778,879 in 2011.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2012, Con Edison's congestion credits were $3,627.462 less than its day-ahead congestion charges (credits had been $2,319,278 more than charges in 2011).

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$42,203 in 2012. The parties should address this issue.

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[55] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special protocol indefinitely.[56] 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.[57] 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 8-27 below reflecting those charges effective May 1, 2012.

54 See "Section 3 – 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.

55 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.

56 132 FERC ¶ 61,221 (2010).

57 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 8-27 Con Edison and PSE&G wheeling agreement data: 2012

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$5,722,599	$104,705	$5,827,303	$865,217	$0	$865,217
Congestion Credit			$2,095,137			$953,303
Adjustments and Transmission Charges			($23,149,300)			($7,358)
Net Charge			$26,881,466			($80,727)

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 called fewer TLRs in 2012 than in 2011. The fact that PJM has issued only 37 TLRs in 2012, compared to 62 in 2011, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM TLRs decreased by 60 percent, from 62 during 2011 to 37 in 2012 (Table 8-28). In addition, the number of different flowgates for which PJM declared TLRs decreased from 18 in 2011 to 13 in 2012. The total MWh of transaction curtailments decreased by 46 percent, from 171,221 MWh in 2011 to 125,783 MWh in 2012.

MISO called more TLRs in 2012 than in 2011. MISO TLRs increased by 11 percent, from 143 in 2011 to 159 in 2012.

Table 8-28 PJM and MISO TLR procedures: January, 2010 through December, 2012[58]

	Number of TLRs Level 3 and Higher		Number of Unique Flowgates That Experienced TLRs		Curtailment Volume (MWh)	
Month	PJM	MISO	PJM	MISO	PJM	MISO
Jan-10	6	23	3	5	18,393	13,387
Feb-10	1	9	1	7	1,249	13,095
Mar-10	6	18	3	10	2,376	27,412
Apr-10	15	40	7	11	26,992	29,832
May-10	11	20	4	12	22,193	54,702
Jun-10	19	19	6	8	64,479	183,228
Jul-10	15	25	8	8	44,210	169,667
Aug-10	12	22	9	7	32,604	189,756
Sep-10	11	15	7	7	82,066	32,782
Oct-10	4	26	3	12	2,305	29,574
Nov-10	1	25	1	10	59	66,113
Dec-10	9	7	6	5	18,509	5,972
Jan-11	7	8	5	5	75,057	14,071
Feb-11	6	7	5	4	6,428	23,796
Mar-11	0	14	0	5	0	10,133
Apr-11	3	23	3	9	8,129	44,855
May-11	9	15	4	7	18,377	36,777
Jun-11	15	14	7	6	17,865	19,437
Jul-11	7	8	4	7	18,467	3,697
Aug-11	4	6	4	4	3,624	11,323
Sep-11	7	17	6	7	6,462	25,914
Oct-11	4	16	2	6	16,812	27,392
Nov-11	0	10	0	5	0	22,672
Dec-11	0	5	0	3	0	8,659
Jan-12	1	9	1	6	4,920	6,274
Feb-12	4	6	2	6	0	5,177
Mar-12	1	11	1	6	398	31,891
Apr-12	0	14	0	7	0	8,408
May-12	2	17	1	10	3,539	30,759
Jun-12	0	24	0	7	0	31,502
Jul-12	11	19	5	4	34,197	46,512
Aug-12	8	13	1	6	61,151	13,403
Sep-12	2	5	1	4	21,134	12,494
Oct-12	3	9	2	6	0	12,317
Nov-12	4	10	2	6	444	24,351
Dec-12	1	22	1	12	0	17,761

58 The curtailment volume for PJM TLR's 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 TLR's 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 January 16, 2013)

Table 8-29 Number of TLRs by TLR level by reliability coordinator: 2012

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2012	ICTE	25	7	11	63	40	0	146
	MISO	75	26	0	16	42	0	159
	NYIS	60	0	0	0	0	0	60
	ONT	47	1	0	0	0	0	48
	PJM	18	19	0	0	0	0	37
	SOCO	0	1	0	0	0	0	1
	SWPP	248	165	5	78	33	0	529
	TVA	55	32	9	7	5	0	108
	VACS	6	4	0	0	0	0	10
Total		534	255	25	164	120	0	1,098

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.

An up-to congestion transaction is analogous to a matched set of incremental offers (INC) and decrement bids (DEC) that are evaluated together and approved or denied as a single transaction, subject to a limit on the cleared price difference. For import up-to congestion transactions, the import pricing point specified looks like an INC offer and the sink looks like a DEC bid. For export transactions, the specified source looks like an INC offer, and the export pricing point looks like a DEC bid. Similarly, for wheel through up-to congestion transactions, the import pricing point chosen looks like an INC offer, and the export pricing point specified looks like a DEC bid. In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. Conversely, an up-to congestion export transaction is submitted and modeled as a withdrawal at the interface, and an injection at a specific PJM node. Wheel through up-to congestion transactions are modeled as an injection at the importing interface and a withdrawal at the exporting interface.

While an up-to congestion bid is analogous to a matched pair of INC offers and DEC bids, there are a number of advantages to using the up-to congestion product. For example, an up-to congestion transaction is approved or denied as a single transaction, will only clear the Day-Ahead Energy Market if the maximum congestion bid criteria is met, is not subject to day-ahead or balancing operating reserve charges and does not have clear rules governing credit requirements. Effective September 17, 2010, up-to congestion transactions were no longer required to pay for transmission.[59]

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 67,295 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 29,665 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011 (See Figure 8-10).

The MMU is concerned about the impacts of the significant increase in up-to congestion transaction volume on the Day-Ahead Energy Market. Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Up-to congestion transactions do not pay operating reserves charges and there is a question as to whether current credit policies adequately address up to congestion transactions. Additionally, the MMU is concerned about the potential for market participants to utilize up-to congestion transactions to affect their other market positions, and the potential impacts that up-to congestion transactions may have on meeting FTR target allocations.

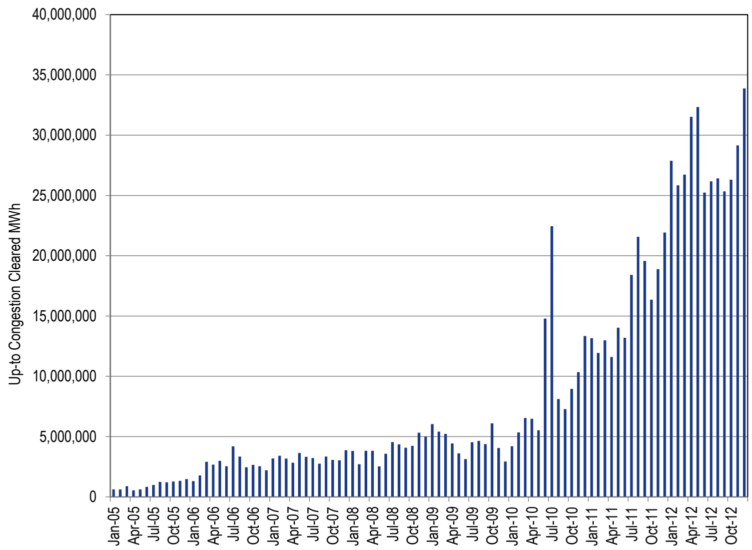
The MMU recommended that the up-to congestion transaction product be eliminated. This product could work as a derivative product traded outside PJM markets and without any of these impacts on the actual operation of PJM markets. Alternatively, the MMU recommended that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges and to make appropriate provisions for credit. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges. To address this concern, in 2012, PJM formed the "Transactions Task Force," with the goal of determining whether or not up-

59 In addition to the cost of transmission, transactions utilizing transmission also incur additional ancillary service charges such as black start and reactive services.

to congestion transaction should be subject to balancing operating reserve charges. After several meetings, the task force was shut down due to fact that the PJM did not believe that it was possible to perform adequate study on the effects of up-to congestion transactions on balancing operating reserves without necessitating a broader scope. While the MMU does not believe that to be the case, the stakeholders agreed with PJM, and the group was dissolved.

While the MMU previously recommended the elimination of all internal PJM buses for use in up-to congestion bidding, 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.

Figure 8-10 Monthly up-to congestion cleared bids in MWh: January, 2006 through December, 2012



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 equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012. While a rate equal to the average of the lowest ten percent of daily operating reserve rates paid by other virtuals would be reasonable, the MMU recommends a rate equal to the average of the lowest 3.3 percent of daily operating reserve rates paid by other virtuals. The average of the daily operating reserve rates paid by virtual transactions was $0.72 per MWh for the lowest ten percent of all days in 2012. The average of the daily operating reserve rates paid by virtual transactions was $0.56 per MWh for the lowest five percent of all days in 2012. The average of the daily operating reserve rates paid by virtual transactions was $0.50 per MWh for the lowest 3.3 percent of all days in 2012.

Table 8-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through December, 2012

	Bid MW					Bid Volume				
Month	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
Feb-09	3,580,115	4,904,467	318,440	-	8,803,022	64,338	70,874	6,347	-	141,559
Mar-09	3,649,978	5,164,186	258,701	-	9,072,865	64,714	72,495	5,531	-	142,740
Apr-09	2,607,303	5,085,912	73,931	-	7,767,146	47,970	67,417	2,146	-	117,533
May-09	2,196,341	4,063,887	106,860	-	6,367,088	40,217	54,745	1,304	-	96,266
Jun-09	2,598,234	3,132,478	164,903	-	5,895,615	47,625	44,755	2,873	-	95,253
Jul-09	3,984,680	3,776,957	296,910	-	8,058,547	67,039	56,770	5,183	-	128,992
Aug-09	3,551,396	4,388,435	260,184	-	8,200,015	64,652	64,052	3,496	-	132,200
Sep-09	2,948,353	4,179,427	156,270	-	7,284,050	51,006	64,103	2,405	-	117,514
Oct-09	3,172,034	6,371,230	154,825	-	9,698,089	46,989	100,350	2,217	-	149,556
Nov-09	3,447,356	3,851,334	103,325	-	7,402,015	53,067	61,906	1,236	-	116,209
Dec-09	2,323,383	2,502,529	66,497	-	4,892,409	47,099	47,223	1,430	-	95,752
Jan-10	3,794,946	3,097,524	212,010	-	7,104,480	81,604	55,921	3,371	-	140,896
Feb-10	3,841,573	3,937,880	316,150	-	8,095,603	80,876	80,685	2,269	-	163,830
Mar-10	4,877,732	4,454,865	277,180	-	9,609,777	97,149	74,568	2,239	-	173,956
Apr-10	3,877,306	5,558,718	210,545	-	9,646,569	67,632	85,358	1,573	-	154,563
May-10	3,800,870	5,062,272	149,589	-	9,012,731	74,996	78,426	1,620	-	155,042
Jun-10	9,126,963	9,568,549	1,159,407	-	19,854,919	95,155	89,222	6,960	-	191,337
Jul-10	12,818,141	11,526,089	5,420,410	-	29,764,640	124,929	106,145	18,948	-	250,022
Aug-10	8,231,393	6,767,617	888,591	-	15,887,601	115,043	87,876	10,664	-	213,583
Sep-10	7,768,878	7,561,624	349,147	-	15,679,649	184,697	161,929	4,653	-	351,279
Oct-10	8,732,546	9,795,666	476,665	-	19,004,877	189,748	154,741	7,384	-	351,873
Nov-10	11,636,949	9,272,885	537,369	-	21,447,203	253,594	170,470	9,366	-	433,430
Dec-10	17,769,014	12,863,875	923,160	-	31,556,049	307,716	215,897	15,074	-	538,687
Jan-11	20,275,932	11,807,379	921,120	-	33,004,431	351,193	210,703	17,632	-	579,528
Feb-11	18,418,511	13,071,483	800,630	-	32,290,624	345,227	226,292	17,634	-	589,153
Mar-11	17,330,353	12,919,960	749,276	-	30,999,589	408,628	274,709	15,714	-	699,051
Apr-11	17,215,352	9,321,117	954,283	-	27,490,752	513,881	265,334	17,459	-	796,674
May-11	21,058,071	11,204,038	2,937,898	-	35,200,007	562,819	304,589	24,834	-	892,242
Jun-11	20,455,508	12,125,806	395,833	-	32,977,147	524,072	285,031	12,273	-	821,376
Jul-11	24,273,892	16,837,875	409,863	-	41,521,630	603,519	338,810	13,781	-	956,110
Aug-11	23,790,091	21,014,941	229,895	-	45,034,927	591,170	403,269	8,278	-	1,002,717
Sep-11	21,740,208	18,135,378	232,626	-	40,108,212	526,945	377,158	7,886	-	911,989
Oct-11	20,240,161	19,476,556	333,077	-	40,049,794	540,877	451,507	8,609	-	1,000,993
Nov-11	27,007,141	28,994,789	507,788	-	56,509,718	594,397	603,029	13,379	-	1,210,805
Dec-11	34,990,790	34,648,433	531,616	-	70,170,839	697,524	655,222	14,187	-	1,366,933
Jan-12	38,906,228	36,928,145	620,448	-	76,454,821	745,424	689,174	16,053	-	1,450,651
Feb-12	37,231,115	36,736,507	323,958	-	74,291,580	739,200	724,477	8,572	-	1,472,249
Mar-12	38,824,528	39,163,001	297,895	-	78,285,424	802,983	842,857	8,971	-	1,654,811
Apr-12	42,085,326	44,565,341	436,632	-	87,087,299	884,004	917,430	12,354	-	1,813,788
May-12	44,436,245	43,888,405	489,938	-	88,814,588	994,735	885,319	10,294	-	1,890,348
Jun-12	38,962,548	32,828,393	975,776	-	72,766,718	872,764	684,382	21,781	-	1,578,927
Jul-12	45,565,682	41,589,191	855,676	-	88,010,549	1,077,721	911,300	27,173	-	2,016,194
Aug-12	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366
Oct-12	35,567,607	42,489,970	1,415,992	-	79,473,570	908,200	1,048,029	46,802	-	2,003,031
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
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
TOTAL	856,092,141	803,098,614	32,495,637	136,570,875	1,828,257,267	18,767,266	16,306,831	608,028	4,398,547	40,080,672

Table 8-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through December, 2012 *(continued)*

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-09	2,591,211	3,242,491	202,854	-	6,036,556	56,132	45,303	4,210	-	105,645
Feb-09	2,374,734	2,836,344	203,907	-	5,414,985	42,101	44,423	4,402	-	90,926
Mar-09	2,285,412	2,762,459	178,507	-	5,226,378	42,408	42,007	4,299	-	88,714
Apr-09	1,797,302	2,582,294	48,478	-	4,428,074	32,088	35,987	1,581	-	69,656
May-09	1,496,396	2,040,737	77,553	-	3,614,686	26,274	29,720	952	-	56,946
Jun-09	1,540,169	1,500,560	88,723	-	3,129,452	28,565	23,307	1,522	-	53,394
Jul-09	2,465,891	1,902,807	163,129	-	4,531,826	41,924	31,176	2,846	-	75,946
Aug-09	2,278,431	2,172,133	194,415	-	4,644,978	41,774	34,576	2,421	-	78,771
Sep-09	1,774,589	2,479,898	128,344	-	4,382,831	31,962	40,698	1,944	-	74,604
Oct-09	2,060,371	3,931,346	110,646	-	6,102,363	31,634	70,964	1,672	-	104,270
Nov-09	2,065,813	1,932,595	51,929	-	4,050,337	33,769	32,916	653	-	67,338
Dec-09	1,532,579	1,359,936	34,419	-	2,926,933	31,673	28,478	793	-	60,944
Jan-10	2,250,689	1,789,018	161,977	-	4,201,684	49,064	33,640	2,318	-	85,022
Feb-10	2,627,101	2,435,650	287,162	-	5,349,913	50,958	48,008	1,812	-	100,778
Mar-10	3,209,064	3,071,712	263,516	-	6,544,292	60,277	48,596	2,064	-	110,937
Apr-10	2,622,113	3,690,889	170,020	-	6,483,022	42,635	54,510	1,154	-	98,299
May-10	2,366,149	3,049,405	112,700	-	5,528,253	47,505	48,996	1,112	-	97,613
Jun-10	6,863,803	6,850,098	1,072,759	-	14,786,660	59,733	55,574	5,831	-	121,138
Jul-10	8,971,914	8,237,557	5,241,264	-	22,450,734	73,232	60,822	16,526	-	150,580
Aug-10	4,430,832	2,894,314	785,726	-	8,110,871	62,526	40,485	8,884	-	111,895
Sep-10	3,915,814	3,110,580	256,039	-	7,282,433	63,405	45,264	3,393	-	112,062
Oct-10	4,150,104	4,564,039	246,594	-	8,960,736	76,042	65,223	3,670	-	144,935
Nov-10	5,765,905	4,312,645	275,111	-	10,353,661	112,250	71,378	4,045	-	187,673
Dec-10	7,851,235	5,150,286	337,157	-	13,338,678	136,582	93,299	7,380	-	237,261
Jan-11	7,917,986	4,925,310	315,936	-	13,159,232	151,753	91,557	8,417	-	251,727
Feb-11	6,806,039	4,879,207	248,573	-	11,933,818	151,003	99,302	8,851	-	259,156
Mar-11	7,104,642	5,603,583	275,682	-	12,983,906	178,620	124,990	7,760	-	311,370
Apr-11	7,452,366	3,797,819	351,984	-	11,602,168	229,707	113,610	8,118	-	351,435
May-11	8,294,422	4,701,077	1,031,519	-	14,027,018	261,355	143,956	11,116	-	416,427
Jun-11	7,632,235	5,361,825	198,482	-	13,192,543	226,747	132,744	6,363	-	365,854
Jul-11	9,585,027	8,617,284	205,599	-	18,407,910	283,287	186,866	7,008	-	477,161
Aug-11	10,594,771	10,875,384	103,141	-	21,573,297	274,398	208,593	3,648	-	486,639
Sep-11	10,219,806	9,270,121	82,200	-	19,572,127	270,088	185,585	3,444	-	459,117
Oct-11	8,376,208	7,853,947	126,718	-	16,356,873	255,206	198,778	4,236	-	458,220
Nov-11	9,064,570	9,692,312	131,670	-	18,888,552	254,851	256,270	5,686	-	516,807
Dec-11	11,738,910	10,049,685	137,689	-	21,926,284	281,304	248,008	6,309	-	535,621
Jan-12	13,610,725	14,120,791	145,773	-	27,877,288	289,524	304,072	5,078	-	598,674
Feb-12	12,883,355	12,905,553	54,724	-	25,843,632	299,055	276,563	2,175	-	577,793
Mar-12	13,328,968	13,306,689	89,262	-	26,724,918	320,210	320,252	3,031	-	643,493
Apr-12	15,050,798	16,297,303	171,252	-	31,519,354	369,273	355,669	4,655	-	729,597
May-12	17,416,386	14,733,838	189,667	-	32,339,891	434,919	343,872	4,114	-	782,905
Jun-12	12,675,852	12,311,609	250,024	-	25,237,485	355,731	295,911	6,891	-	658,533
Jul-12	13,001,225	12,823,361	348,946	-	26,173,532	399,135	321,062	9,958	-	730,155
Aug-12	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
Oct-12	11,969,576	13,949,871	392,286	-	26,311,733	345,788	376,513	14,089	-	736,390
Nov-12	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	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
TOTAL	330,503,051	314,515,740	16,877,010	36,440,790	698,336,591	7,992,622	6,853,230	278,290	1,330,427	16,454,569

In 2012, the cleared MW volume of up-to congestion transactions were comprised of 43.5 percent imports, 44.8 percent exports, 0.9 percent wheeling transactions and 10.8 percent internal transactions. Only 0.2 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. This 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 locational marginal prices at interfaces accurately reflect the price of energy at the interfaces based on the modeled impacts of actual flows when energy is transferred between markets. 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 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. These modifications are currently being evaluated by PJM.

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 2012 were -$11,789, compared to -$20,955 in 2011 (Table 8-31). 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 2012. 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 2012, 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. These modifications are currently planned for implementation on March 1, 2013.

Table 8-31 Monthly uncollected congestion charges: 2010 through 2012

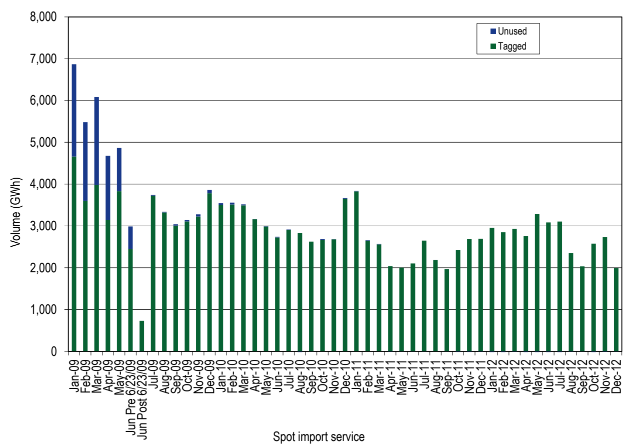
Month	2010	2011	2012
Jan	$148,764	$3,102	$0
Feb	$542,575	$1,567	($15)
Mar	$287,417	$0	$0
Apr	$31,255	$4,767	($68)
May	$41,025	$0	($27)
Jun	$169,197	$1,354	$78
Jul	$827,617	$1,115	$0
Aug	$731,539	$37	$0
Sep	$119,162	$0	$0
Oct	$257,448	($31,443)	($6,870)
Nov	$30,843	($795)	($4,678)
Dec	$127,176	($659)	($209)
Total	$3,314,018	($20,955)	($11,789)

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. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports.[60] 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. After a series of rule changes intended to address the hoarding of spot in service that resulted from this change, and after several conversations with MISO regarding the limitation of spot market imports, PJM and MISO have agreed to allow for unlimited spot market ATC on the NYISO Interface. These modifications are currently being evaluated by PJM. The MMU continues to recommend that PJM permit unlimited spot market imports and exports at all PJM Interfaces.

Figure 8-11 Spot import service utilization: January, 2009 through December, 2012



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

60 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>. (Accessed January 16, 2013)

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. During 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.3 million for 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that dispatchable schedules were only submitted for three days during 2012.

NYISO Interface Pricing Error

On October 8, 2012, in compliance with the PJM Tariff and Operating Agreement, PJM provided notification to market participants after an error was identified in the calculation of the NYIS Interface LMP calculation that occurred starting on October 1, 2012.[61] The error was related to the congestion components of the underlying buses that make up the NYIS Interface price definition. The PJM Tariff only permits modifications to posted Real-Time Energy Market prices in cases where market participants are notified within two business days of the operating day. Therefore, corrections to the prices for the period spanning October 1, 2012, through October 3, 2012 could not be made. PJM determined that there were only minor differences in the calculated prices for October 4, 2012, and PJM did not repost prices for that day.

The error was corrected on October 6, 2012. On October 8, 2012, through the LMP verification process, PJM corrected the previously posted prices for the period from October 5, 2012, through the time the issue was resolved on October 6, 2012.

61 OATT Attachment K (Office of the Interconnection Responsibilities) § 1.10.8 (e)

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.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve. Beginning October 1, 2012 with the implementation of Shortage Pricing, primary reserve is also satisfied by non-synchronized reserve subject to the restriction that at least 50 percent of primary reserve must be synchronized reserve.

The Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets are cleared, prior to the market hour, and supplementally within the hour, on a real-time basis. The Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets are cleared and priced interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, inter area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements, and prior to the hour assignments for regulation and reserves.

The purpose of the Day-Ahead Scheduling Reserve (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 the market clearing price.[2]

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

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 all of 2012.

Table 9-1 The Regulation Market results were not competitive for the first three quarters and were indeterminate for the fourth quarter[3]

	January through September, 2012		October through December, 2012	
Market Element	Evaluation	Market Design	Evaluation	Market Design
Market Structure	Not Competitive		Not Competitive	
Participant Behavior	Competitive		Competitive	
Market Performance	Not Competitive	Flawed	To Be Determined	To Be Determined

1 75 FERC ¶ 61,080 (1996).

2 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

3 As Table 9-1 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the market rules, in particular the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

- 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 43 percent of the hours in 2012.[4]
- Participant behavior in the Regulation Market was evaluated as competitive for the year 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 not competitive for the first three quarters, despite competitive participant behavior, because prior changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.[5]
- Market performance was evaluated as indeterminate for the fourth quarter, 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 remain to be decided by FERC and because there is not yet enough information on performance.
- Market design was evaluated as flawed for the first three quarters because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there were additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.
- Market design was evaluated as indeterminate for the fourth quarter, 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. It is too early to reach a definitive conclusion about the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information about actual implementation of the design.

4 These TPS results reflect MMU estimates for the period between May 6 and July 21, 2012, when the TPS test was not correctly applied by PJM.

5 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

Table 9-2 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 Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 22 percent of the hours in 2012.
- 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 prices that reflect marginal costs.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 9-3 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), about 12 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

In 2012, the PJM Regulation Market continued 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, the Ancillary Services Optimizer (ASO). On October 1, 2012, PJM implemented Performance Based Regulation, to comply with FERC Order No. 755.[6] On November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[7]

Market Structure

- **Supply.** In 2012, 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 3.61 for 2012. This is a 20.3 percent increase over 2011 when the ratio was 3.00.
- **Demand.** The on-peak regulation requirement, as of December 31, 2012, 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. In 2011, the on-peak regulation requirement was equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement was equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in 2012 was 921 MW (840 MW off peak, and 1,015 MW on peak). This is a 4 MW decrease in the average hourly regulation demand of 925 MW in 2011 (842 MW off peak, and 1,071 MW on peak).

  Of the LSEs' obligation to provide regulation during 2012, 78.6 percent was purchased in the spot market (81.8 percent in 2011), 19.0 percent was self scheduled (15.6 percent in 2011), and 2.5 percent was purchased bilaterally (2.6 percent in 2011).[8]
- **Market Concentration.** In 2012, the PJM Regulation Market had a weighted, average Herfindahl-Hirschman Index (HHI) of 1,735 which is classified as "moderately concentrated."[9] The minimum hourly HHI was 788 and the maximum hourly HHI was 4962.[10] In 2012, 43 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (82.1 percent of hours failed the three pivotal supplier test in 2011). The MMU concludes from these results that the PJM Regulation Market in 2012 was characterized by structural market power in 43 percent of the hours.

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 costs 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.[11] As of December 31, 2012, there were seven distinct resources (three generation and four demand response) offering performance regulation and following the RegD signal.
- **Price.** The weighted Regulation Market clearing price for the PJM Regulation Market for January through September, 2012 was $14.92 per MWh. This was a decrease of $2.11, or 12.4 percent, from the

6 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

7 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,130 (2012)

8 Due to rounding, percentages might not sum to 100 percent.

9 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.

10 HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. This assumption and related conclusion are not generally correct in electricity markets, like the Regulation Market, where location and unit specific parameters are significant determinants of the costs to provide service, not the relative market share of the participant. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

11 See Appendix F "Ancillary Services Markets."

weighted average price for regulation in January through September, 2011. The cost of regulation from January through September, 2012 was $20.59 per MWh. This is an $11.64 (36.1 percent) decrease from the same time period in 2011.

The Regulation Market changed significantly on October 1, 2012, with the introduction of Performance Regulation. For October through December 2012, the weighted average market clearing price was $36.52 per MWh. This is a 148.2 percent increase from the weighted average market clearing price of $14.71 for the same period in 2011. The total cost of regulation from October through December 2012, was $43.86 per MWh. This is a $23.40 per MWh increase (114.3 percent) over the cost of regulation during the same time period of 2011.

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 now merged with the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated Dominion to become the Mid-Atlantic Dominion Reserve Zone. PJM further retains the right to define new zones or subzones "as needed for system reliability."[12]

Market Structure

- **Supply.** In 2012, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side 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, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Sub-zone became the Mid-Atlantic Dominion Sub-zone on October 1, the requirement remained at 1,300 MW.
- **Market Concentration.** For all of 2012, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 3570 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in 2011 was 2637, which is classified as "highly concentrated."[13] In 2012, 56 percent of hours had a maximum market share greater than 40 percent, compared to 46 percent of hours in 2011.

  In the Mid-Atlantic Subzone, in 2012, 22 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In 2011, 63 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 2012 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 Subzone was $8.02 per MW in 2012, a $3.79 per MW decrease from 2011. The total cost of synchronized reserves per MWh in 2012 was $12.71, a $2.77 decrease (17.9 percent) from the $15.48 cost of synchronized reserve in 2011. The market clearing price was 65 percent of the total synchronized reserve cost per MW in 2012, down from 76 percent in 2011.

  One goal of shortage pricing is to have the synchronized reserve price reflect the total cost of synchronized reserve. Although both price and cost

12 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 74.

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

are lower in 2012, the price/cost ratio was high from October through December, 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 2012.

DASR

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[14] The purpose of this 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.[15] 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 2012, 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 2012, the required DASR was 7.03 percent of peak load forecast, down from 7.11 percent in 2011.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero; however, there is an opportunity cost associated with this direct marginal cost. As of December 31, 2012, twelve percent of offers reflected economic withholding. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[16] Units that do not offer have their offers set to zero.
- **DSR.** Demand side resources do participate in the DASR Market, but no demand resource cleared the DASR Market in 2012.

Market Performance

- **Price.** The weighted DASR market clearing price in 2012 was $0.57 per MW. In 2011, the weighted price of DASR was $0.55 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.[17]

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 all costs associated with providing this service, as defined in the tariff. In 2012, black start charges were $50.2 million. This is 151 percent higher than 2011, when total black start service charges were $20.0 million. There was substantial zonal variation. Black start zonal charges in 2012 ranged from $0.02 per MW in the ATSI zone (total charges: $119,167) to $3.62 per MW in the AEP zone (total charges: $32,468,706).

Ancillary services costs per MW of load: 2001 - 2012

Table 9-4 shows PJM ancillary services costs for 2001 through 2012 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

14 See 117 FERC ¶ 61,331 (2006).

15 See PJM. "Manual 13: Emergency Operations," Revision 52, (February 1, 2013); pp 11-12.

16 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 141.

17 OATT Schedule 1 § 1.3BB.

Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

Table 9-4 History of ancillary services costs per MW of Load[18]: 2001 through 2012

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2001	$0.50	$0.44	$0.22	$0.00	$1.07	$2.23
2002	$0.45	$0.53	$0.21	$0.07	$0.63	$1.90
2003	$0.50	$0.61	$0.24	$0.14	$0.83	$2.32
2004	$0.50	$0.60	$0.25	$0.13	$0.90	$2.38
2005	$0.79	$0.47	$0.26	$0.11	$0.93	$2.57
2006	$0.53	$0.48	$0.29	$0.08	$0.43	$1.81
2007	$0.63	$0.47	$0.29	$0.06	$0.58	$2.02
2008	$0.68	$0.40	$0.31	$0.08	$0.59	$2.06
2009	$0.34	$0.32	$0.37	$0.05	$0.48	$1.56
2010	$0.34	$0.38	$0.41	$0.07	$0.73	$1.93
2011	$0.32	$0.34	$0.42	$0.10	$0.77	$1.95
2012	$0.26	$0.40	$0.43	$0.04	$0.79	$1.92

Conclusion

The MMU continues to conclude that the results of the Regulation Market were not competitive in the first three quarters of 2012.[19] The Regulation Market results were not competitive because the 2008 changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic and the definition of opportunity cost elsewhere in the PJM tariff. This conclusion is not based on the behavior of market participants, which remains competitive.

PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU recommends that the definition of opportunity cost be consistent across all markets.

More importantly for the Regulation Market is that the design of the market was changed very 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 important parts of the design remain to be decided by FERC and 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 is cause for optimism with respect to 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. However, compliance with calls to respond to actual spinning events has been an issue. As a result, the MMU recommends that the rules for compliance be reevaluated.

The MMU concludes that the DASR Market results were competitive in 2012, 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.

18 Results in this table differ slightly from the results reported previously because accounting load is used in the denominator in this table.

19 The *2009 State of the Market Report for PJM* provided the basis for this conclusion. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market. See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Overall, the MMU concludes that the Regulation Market results were not competitive in the first three quarters of 2012 as a result of the identified market design issues but that although it is not yet possible to reach a definitive conclusion about the new design, there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in 2012. The MMU concludes that the DASR Market results were competitive in 2012.

Regulation Market

Throughout 2012, the PJM Regulation Market continued 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.[20] On November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[21]

Regulation Market Changes for Performance Based Regulation

Regulation is a key part of PJM's effort to minimize ACE so as to keep the reportable metrics CPS1 and BAAL within acceptable limits.[22] On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation markets to make use of and properly compensate a mix of fast and traditional response regulation resources.[23] A driver 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. FERC directed 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. 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, 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.

As part of the implementation process of the new Regulation Market design, PJM conducted studies that showed that new, fast response technologies could be used, in combination with traditional resources, to reduce the amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. These studies showed that resources following a fast response signal (RegD) are, up to a point and at a diminishing rate, a substitute for resources following a slow response signal (RegA).

In the study, the rate of substitution between RegA and RegD following resources is dependent on the proportion of RegA to RegD resources employed. The effectiveness (in minimizing ACE) of RegD following resources falls as the proportion of RegD following resources to RegA following resources increases. The PJM Regulation Market, as proposed in its August 15, 2012 filing, seeks to clear an optimal, least cost mix of RegA and RegD following resources, using a single overall clearing price for regulation service.

The clearing of two different resources types in a single market with uniform pricing requires that the two resources be converted into comparable units. A resource following RegA provides regulation service measured in MW of capability and miles of movement per MW of capability. A resource following RegD also provides regulation service, but the amount of regulation service provided is measured in terms of RegA. The conversion of units of RegD into units of RegA occurs through the use of what is termed a benefits factor. The marginal benefits factor describes how much regulation can be provided by the next increment of a RegD resource, measured in terms of equivalent RegA regulation MW. This translation into equivalent RegA MW of regulation is required in order to have an efficient market clearing mechanism with a single price. The marginal benefits factor is based on the physical, engineering characteristics of the system and the resultant relative effectiveness of RegA and RegD resources in meeting the system's need for regulation. The amount of regulation

20 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

21 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,130 (2012)

22 See the *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services, p.1

23 Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137 FERC ¶ 61,064 (2011) ("Order No. 755").

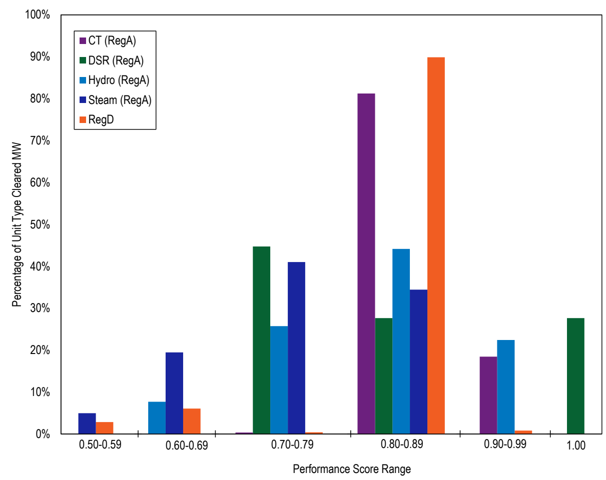
provided by a unit of RegD measured in terms of RegA units depends on these observed system characteristics.

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. Between October 1, 2012, and December 31, 2012, the lowest actual marginal benefit factor was 2.02. 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 100-hour average of performance scores. A unit's regulation capability MW multiplied by its benefits factor, and modified by its performance score, results in that unit's effective RegA signal following regulation MW.[24] Figure 9-1 shows the performance score distribution of that unit type from October through December, 2012.

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 settlement in PJM's regulation market through the remainder of 2012.

Performance tracking is an essential element of the performance based Regulation Market. Every regulating unit for every hour has its performance tracked, measured, and recorded. An hourly performance score (0.0 to 1.0) 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. Units are cleared and compensated for their effective MW. Regulation performance score measures 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.[25] Figure 9-1 shows the average performance score by unit type and signal followed.

Figure 9-1 Average performance score grouped by unit type and regulation signal type: October-December 2012



The use of a performance score to measure the accuracy of a regulating resource is the primary reason that the required regulation has been lowered from 1.0 percent to 0.7 percent. Initially, the required regulation was lowered from 1 percent to 0.78 percent of forecast peak load.[26] As of December 31, 2012, the regulation requirement was 0.70 percent of peak load forecast. PJM historically procured regulation MW without performance adjustment. In order to make sure it had enough effective regulation, PJM set its regulation requirement, in terms of regulation MW, equal to 1.0 percent of total expected peak demand. With the introduction of the performance adjustment for regulation MW provided under the new market design, PJM is better able to determine the effective amount of regulation MW it is purchasing from individual resources. The performance adjustment converts raw regulation capability MW into effective regulation capability MW. With a conversion of regulation supply

24 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 57, (December 1, 2012); para 3.2.7, pp 62.

25 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); para. 4.5.6, pp 52.

26 See PJM "Manual 12: Balancing Operations," Revision 27, (December 20, 2012); para 4.4.3, pp 44.

into effective MW, PJM's regulation requirement was similarly converted to units of effective regulation MW, resulting in the reduction in the regulation requirement, measured in effective regulation MW, as a percentage of 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.

The implementation of Shortage Pricing on October 1, 2012 significantly changed the way ancillary services markets are cleared and priced. The Regulation Market is cleared and assignments made hourly through a joint optimization of energy, reserves, and regulation by the Ancillary Service Optimizer (ASO). The ASO performs the regulation three-pivotal supplier test and makes hourly assignment of cleared regulating units. The ASO does not calculate clearing prices. Units that clear and are assigned to regulate for the hour will continue to regulate for that hour but their pricing is recalculated every five minutes by the Locational Pricing Calculator (LPC). Before October 1 the cost of a regulation unit in the regulation market was calculated as the regulation offer plus the lost opportunity cost (as a function of the forecast LMP). After October 1, the adjusted total offer cost of a unit in the regulation market is calculated by the sum of the adjusted regulation performance offer price, the adjusted regulation capability price, and the adjusted LOC. Using the adjusted total offer cost, both the regulation market capability clearing price and the regulation market performance clearing price are computed from the highest adjusted offer for each of those prices among the assigned regulation units. The final regulation market clearing price (calculated in 5-minute intervals and averaged to an hourly RMCP) is the sum of the regulation market capability clearing price (RMCCP) and the regulation market performance clearing price (RMPCP).

Market Structure

Supply

Table 9-5 shows capability, average daily offer and average hourly eligible MW for all hours. The hourly regulation capability increased in 2012, to 9,413 MW from 8,871 MW in 2011. Eligible regulation as a percentage of capability increased by four percent over 2011.

Table 9-5 PJM regulation capability, daily offer[27] and hourly eligible: 2011 and 2012[28]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
2011 (Jan-Sep)	8,808	5,970	68%	2,742	31%
2012 (Jan-Sep)	9,413	6,656	71%	3,089	33%
2011 (Oct-Dec)	8,871	6,446	73%	2,680	30%
2012 (Oct-Dec)	8,235	6,224	76%	3,228	39%
2011	8,871	6,083	69%	2,723	31%
2012	9,413	6,551	70%	3,253	35%

The supply of regulation can be affected by regulating units retiring from service. Table 9-6 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015.

Table 9-6 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, 2012	Settled MW, 2012	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
302	8,225,023	53	206,197	2.51%

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 ($/MW) and performance offer ($/ΔMW). 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

27 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

28 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.

the hour. The total clearing price of 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 significantly higher than they were prior to October 1, 2012. Since required regulation is now reduced to 0.70 percent of peak load forecast (from one percent of peak load forecast prior to October 1) the overall cost of regulation while high in October and November, returned to historical levels in December. The ratio of price to cost is higher, meaning that more of the costs which used to come from LOC as a result of low load forecasts are now part of the price.

Since October 1, a number of resources have offered and cleared the regulation market following the RegD signal. As of the end of 2012 the use of the RegD signal was beginning to show wider participation.

In the period from October 1, 2012 through December, 2012, the marginal benefits factor (contribution to ACE correction) for cleared RegD following resources has ranged from 2.2 to 2.7.

If the set of resources that follow RegD were to be considered as a separate market, their HHI from October through December, 2012 would be 8422.

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 October through December, 2012, the average performance score was 0.79.

Figure 9-2 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation; October through December, 2012

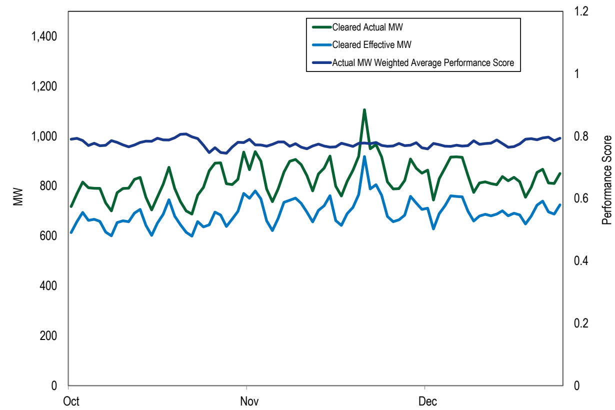
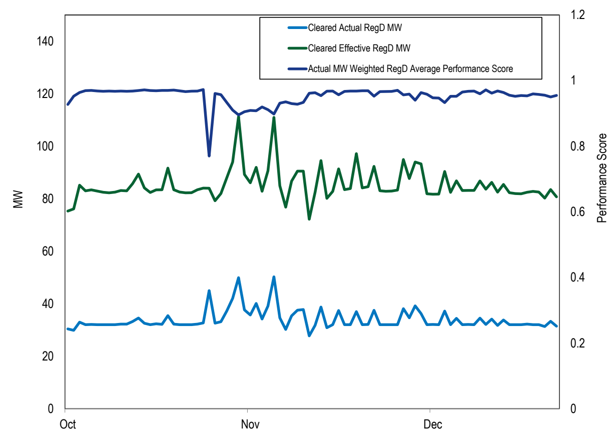


Figure 9-3 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units only; October through December, 2012



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, averaging about 2.6 (Figure 9-3). The average RegD resource performance score was 0.96.

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. 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. Before October 1, the requirement had been 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. Table 9-7 shows the required regulation and its relationship to the supply of regulation.

Table 9-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: Calendar years 2011 and 2012

Month	Average Required Regulation (MW), 2011	Average Required Regulation (MW), 2012	Ratio of Supply to Requirement, 2011	Ratio of Supply to Requirement, 2012
Jan	960	1,005	3.19	3.29
Feb	897	979	3.06	3.45
Mar	823	876	3.02	3.14
Apr	747	826	2.87	3.19
May	786	918	2.84	3.26
Jun	1,037	1,055	2.81	3.21
Jul	1,214	1,246	2.79	2.94
Aug	1,093	1,134	2.83	2.97
Sep	922	941	2.74	3.33
Oct	821	772	3.04	4.28
Nov	855	708	3.01	4.63
Dec	934	701	3.25	5.60

The regulation requirement is designed to ensure that regulation minimizes ACE excursions and time deficits. NERC has establishes several measures of control performance that PJM reports; CPS1, CPS2, and BAAL. PJM's performances as measured by CPS and BAAL standards has not been reduced in spite of the lower regulation requirement.[29]

Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for 2011 and 2012. The average HHI of 1735 is classified as moderately concentrated.

Table 9-8 PJM cleared regulation HHI: 2011 and 2012

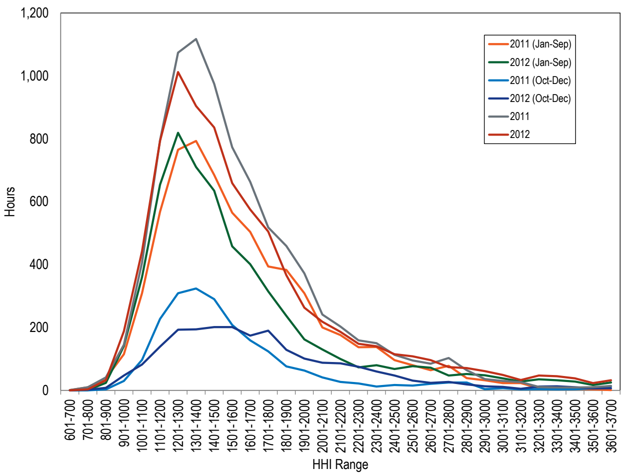
Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2011 (Jan-Sep)	818	1645	3683
2012 (Jan-Sep)	810	1529	4962
2011 (Oct-Dec)	841	1543	4005
2012 (Oct-Dec)	788	1673	4339
2011	818	1630	4005
2012	788	1735	4962

Figure 9-4 compares the 2012 HHI distribution curves with distribution curves for the same periods of 2011 and 2010.

Table 9-9 includes a monthly summary of three pivotal supplier results. In 2012, 43 percent of hours had one or more pivotal suppliers which failed or should have failed PJM's three pivotal supplier test.[30] Pivotal supplier test results improved after October 1, 2012 when Regulation Performance Pricing took effect. The combination of lower required MW (one percent of peak load declining to 0.7 percent of peak load) and higher clearing prices increased the diversity of eligible regulation providers.

The MMU concludes from these results that the PJM Regulation Market in 2012 was characterized by structural market power in 43 percent of the hours.

Figure 9-4 PJM Regulation Market HHI distribution: 2011 and 2012



29 *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services.

30 The MMU monitors the application of the TPS test by PJM and brings any issues to the attention of PJM.

Table 9-9 Regulation market monthly three pivotal supplier results: 2010, 2011 and 2012[31]

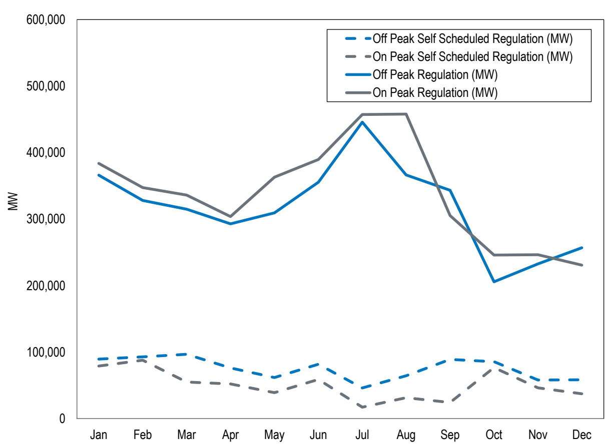
	Percent of Hours Pivotal		
Month	2012	2011	2010
Jan	71%	95%	74%
Feb	67%	93%	70%
Mar	64%	94%	83%
Apr	41%	97%	82%
May	*37%	95%	79%
Jun	*40%	89%	81%
Jul	*13%	89%	75%
Aug	32%	83%	69%
Sep	35%	87%	70%
Oct	19%	67%	47%
Nov	18%	46%	63%
Dec	40%	50%	89%

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 9-10).[32]

Figure 9-5 Off peak and on peak regulation levels: 2012



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 during 2012, 78.6 percent was purchased in the spot market (81.8 percent in 2011), 19.0 percent was self scheduled (15.6 percent in 2011), and 2.5 percent was purchased bilaterally (2.6 percent in 2011). (Table 9-10).

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: 2011 and 2012

Year	Month	Spot Regulation (MW)	Self-Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)
2011	Jan	575,975	116,226	16,670	708,871
2011	Feb	462,229	115,250	17,553	595,032
2011	Mar	464,862	107,496	28,107	600,464
2011	Apr	419,449	86,614	18,275	524,338
2011	May	466,780	81,699	15,977	564,456
2011	Jun	588,022	89,368	15,128	692,518
2011	Jul	754,390	39,324	15,647	809,361
2011	Aug	722,598	67,277	14,442	804,318
2011	Sep	566,419	81,607	15,062	663,088
2011	Oct	479,901	113,104	15,063	608,068
2011	Nov	456,942	137,050	16,313	610,304
2011	Dec	475,496	191,618	19,445	686,559
2012	Jan	553,686	164,806	21,261	739,753
2012	Feb	481,004	175,757	20,456	677,217
2012	Mar	477,564	144,408	19,683	641,655
2012	Apr	426,564	124,750	21,083	572,397
2012	May	542,585	97,574	17,849	658,008
2012	Jun	582,078	140,769	22,309	745,156
2012	Jul	819,897	63,415	19,711	903,024
2012	Aug	710,715	95,949	17,687	824,350
2012	Sep	518,046	114,495	19,726	652,267
2012	Oct	287,616	162,555	1,539	451,710
2012	Nov	369,075	104,386	5,727	479,188
2012	Dec	385,468	95,903	6,378	487,749

Demand resources offered and cleared regulation for the first time in November 2011. In April 2012, a tariff change allowing demand resources to offer 0.1 MW facilitated participation by demand resources. Although their impact remains small the participation of demand resources in regulation is growing. For October through December every hour cleared some demand resources.

The Minimum Regulation MW parameter was reintroduced in 2012. This parameter allows regulation owners to specify a minimum amount of regulation that can be cleared, which imposes a constraint on the ASO's three product optimization. For the marginal unit, the ASO may need to clear less than an individual unit's offered amount of regulation in order to meet the regulation requirement. As a result of this parameter, there are a significant number of hours in which the ASO will have to clear more MW than is optimal or skip the marginal unit and clear a more expensive unit resulting in a higher Regulation Market Clearing Price.

31 The results for May, June and July, 2012 are MMU estimates.

32 See PJM "Manual 28: Operating Agreement Accounting," Revision 57, (December 1, 2012); para 4.2, pp 14.

Market Performance

Price

The weighted average regulation market clearing price for January through September 2012 was $14.92. This is a 12.4 percent decrease from the weighted average market clearing price of $17.03 for the same period in 2011. For October through December 2012, the weighted average market clearing price was $36.52. This is a 148.2 percent increase from the weighted average market clearing price of $14.71 for the same period in 2011. In all of 2012, the weighted average market clearing price was $19.04. This is a 17.5 percent increase from the 2011 weighted average market clearing price of $16.21.

Figure 9-6 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. Table 9-11 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC. All units chosen to provide regulation received the higher of the clearing price, or the unit's regulation offer plus the individual unit's real-time opportunity cost, based on actual LMP.[33] The purpose of 5-minute pricing using real-time LMPs to shift what had been after-market LOCs into the price so that the price more nearly reflects the full cost of regulation. The implementation of Shortage Pricing and Performance Regulation on October 1, 2012 was followed by several changes of software and market operations procedure between October 1 and December 1. Although regulation prices were historically high from October through December, the December price was closer to the January-September average regulation prices and the ratio of price to cost was at a high level, 89 percent, indicating that the price more closely reflects the cost.

The average capability offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during October through December, 2012, was $5.37 per MWh, a decrease from the average offer in October through December 2011 of $11.01 (Table 9-11).

The average opportunity cost of the marginal unit for the PJM Regulation Market in October through December 2012 was $27.67. This is an increase from the average opportunity cost for the marginal unit during the same period of 2012 of $3.47. In the PJM Regulation Market the marginal unit opportunity cost averaged 76 percent of the RMCP. This is a decrease from the October through December, 2011, average of 20 percent.

Figure 9-6 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): 2012

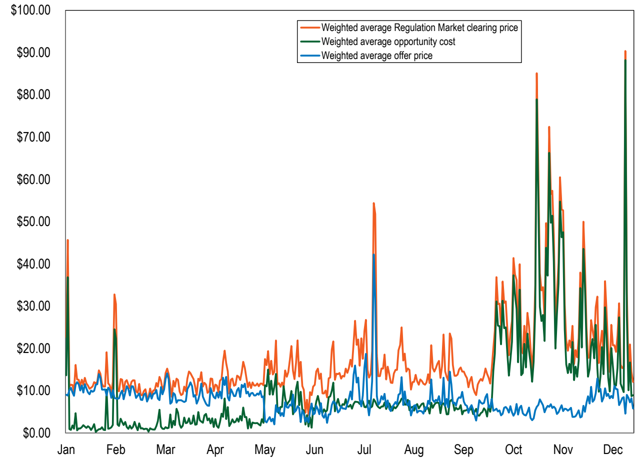


Table 9-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through December 2012

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$13.41	$10.58	$2.70
Feb	$11.89	$8.84	$2.68
Mar	$12.61	$8.82	$3.48
Apr	$13.01	$8.63	$4.07
May	$17.44	$6.52	$9.89
Jun	$14.91	$6.21	$6.94
Jul	$20.73	$6.60	$10.70
Aug	$15.86	$6.50	$7.37
Sep	$14.42	$5.46	$7.16
Oct	$39.80	$5.14	$23.94
Nov	$42.71	$5.58	$32.33
Dec	$27.39	$8.50	$20.19
Average	$20.35	$7.28	$10.95

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 9-12.

33 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 57, Section 4.2, "Regulation Credits" (December 1, 2012), p. 15. PJM uses estimated opportunity cost to clear the market and actual opportunity cost to compensate generators that provide regulation and synchronized reserve.

Table 9-12 Total regulation charges: 2012 and 2011

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percentage of Cost
2011	Jan	709,121	$20,116,704	$11.77	$28.37	41%
2011	Feb	594,515	$14,551,995	$11.33	$24.48	46%
2011	Mar	599,608	$12,967,924	$11.42	$21.63	53%
2011	Apr	523,565	$15,361,871	$15.56	$29.34	53%
2011	May	566,439	$23,561,565	$17.92	$41.60	43%
2011	Jun	691,666	$27,696,820	$23.38	$40.04	58%
2011	Jul	810,656	$37,375,988	$23.61	$46.11	51%
2011	Aug	803,781	$26,271,979	$19.10	$32.69	58%
2011	Sep	662,237	$17,074,805	$16.07	$25.78	62%
2011	Oct	608,213	$12,437,431	$14.30	$20.45	70%
2011	Nov	637,312	$14,929,690	$17.57	$23.43	75%
2011	Dec	685,895	$11,993,503	$12.48	$17.49	71%
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	$18,285,825	$15.86	$22.18	72%
2012	Sep	652,267	$13,676,276	$14.42	$20.97	69%
2012	Oct	451,710	$22,089,570	$39.80	$48.90	81%
2012	Nov	479,188	$24,908,205	$42.71	$51.98	82%
2012	Dec	487,749	$14,970,348	$27.39	$30.69	89%

Table 9-13 Components of regulation cost: 2012

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	739,753	$13.41		$4.62	$18.03
Feb	677,217	$11.89		$3.04	$14.93
Mar	641,655	$12.61		$4.70	$17.31
Apr	572,397	$13.01		$2.78	$15.79
May	658,008	$17.44		$7.25	$24.69
Jun	745,156	$14.91		$4.12	$19.03
Jul	903,024	$20.73		$11.64	$32.37
Aug	824,350	$15.88		$6.30	$22.18
Sep	652,267	$14.43		$6.54	$20.97
Oct	451,710	$30.90	$8.95	$9.05	$48.90
Nov	479,188	$36.58	$6.18	$9.22	$51.98
Dec	487,749	$21.23	$6.20	$3.26	$30.69

Table 9-14 Comparison of average price and cost for PJM Regulation, 2006 through 2012

Period	Weighted Regulation Market Price ($/MW)	Weighted Regulation Market Cost ($/MW)	Regulation Price as Percent Cost
2006	$32.69	$44.98	73%
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	$16.21	$29.28	55%
2012	$20.35	$26.41	77%

Table 9-12 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 2012 than it was 2011.

Both regulation prices and costs rose significantly after the implementation of Performance Regulation on October, 1, 2012 (Table 9-12). In December, however, after a software change, the total cost of regulation dropped. Although prices remain high, significantly fewer MW are cleared. Also, since LOC costs that had been paid at settlements time are now shifted into the real-time price calculation, the ratio of price to cost is the highest it has ever been at 89 percent in December.

Primary Reserve

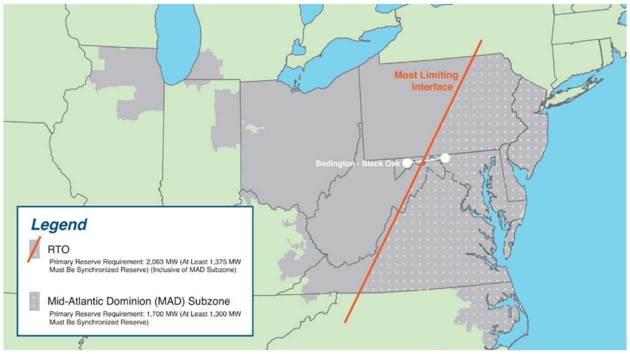
Reserve is generating capability that is standing by ready for service if an unforeseen event causes a sudden need for it. The need can be short-term and critical in the event of a disturbance or generator outage or longer term. NERC defines such losses and defines reporting requirements in "NERC Performance Standard BAL-002-0, Disturbance Control Performance." PJM defines its obligation in M-12[34]. NERC calls short-term reserve contingency reserve and specifies it as energy available in 15 minutes. PJM satisfies this requirement and calls it Primary Reserve. PJM specifies it more restrictively as energy available within 10 minutes. Historically PJM has further restricted this by specifying that the energy be on-line and synchronized. This excluded some units (such as hydro and CT units) which could deliver energy within 10 minutes from a shutdown state because shutdown units were considered less reliable. PJM now allows units in a shutdown state to satisfy the primary reserve requirement. PJM still retains a synchronized reserve requirement.

34 See PJM. "Manual 12: Balancing Operations" Revision 27, Attachment D, "Disturbance Control Performance/Standard" (December 20, 2012), p. 84.

Requirements

PJM must satisfy 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 must be on-line and synchronized to the grid (Figure 9-7).

Figure 9-7 PJM RTO primary reserve requirement: October through December 2012



Because of constrained deliverability within the RTO, PJM imposes a further restriction by creating a sub-zone within the RTO called the Mid-Atlantic Dominion sub-zone. Of the 2,063 MW requirement for primary reserve in the RTO, 1,700 MW must be deliverable to the Mid-Atlantic Dominion sub-zone. Of the 1,375 MW of synchronized reserve in the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion sub-zone. The Mid-Atlantic Dominion sub-zone is defined approximately by the geography in Figure 9-7. It is defined exactly by the set of all resources with a three percent or greater DFAX raise help on the constrained side of the most limiting constraint, currently Bedington-Black Oak.[35]

The primary reserves requirement is not satisfied by a single market but by several products across the RTO Zone and Mid-Atlantic Dominion Sub-zone as optimized by the Ancillary Services Optimizer (ASO). 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 energy products optimized to ensure their least total price (Figure 9-8). The components of the Mid-Atlantic Dominion Primary Reserve Zone are Tier 1 MW which is priced at $0 unless there is a shortage event or a spinning event, Tier 2 synchronized reserve which is satisfied by the Synchronized Reserve Market and priced economically, Demand Response (DSR) which is priced at the Synchronized Reserve Market clearing price, non-synchronized reserve (limited to no more than 50 percent of the primary reserve requirement) which is priced only when it must be dispatched at an optimized clearing price by the ASO, and synchronized reserve available in the Mid-Atlantic Dominion Reserve Zone from the RTO Reserve Zone across the most limiting constraint (usually Bedington-Black Oak).

Figure 9-8 Components of Mid-Atlantic Sub-Zone Primary Reserve (Daily Averages): October through December, 2012

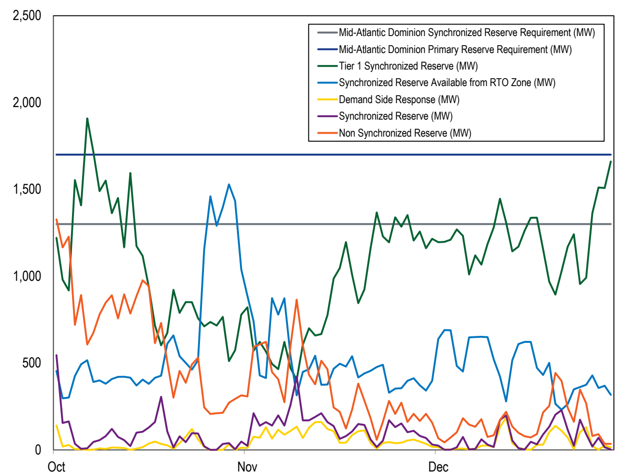


Figure 9-8 shows that Tier 1 Synchronized Reserve remains the major contributor to the reserve requirements. Synchronized reserve available inside the sub-zone from the RTO Zone is also a major contributor. Both of these components usually have a price of $0.00 unless a Tier 2 Synchronized Reserve or Non-Synchronized Reserve market is cleared in the RTO Zone. Non-synchronized reserve is the next most important component of primary reserve. Although it is more often a component of the primary reserve it clears a separate market less frequently because (like DASR) it is available without re-dispatch from CTs and some hydro units. Finally synchronized reserve is dispatched usually at an optimized clearing price as calculated by the LPC.

35 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 57 (December 1, 2012), p. 74.

The ASO must satisfy the primary reserve requirement and the synchronized reserve requirement subject to the constraint that at least 1,300 MW of the 1,700 MW required for primary reserve must be synchronized reserve. In this effort it will select first Tier 1 synchronized reserve which is higher quality than non-synchronized reserve and is priced at $0.00. When all Tier 1 has been identified, if it is enough to satisfy the 1,300 MW synchronized reserve requirement (which it was in about 57 percent of hours in the Mid-Atlantic Dominion Subzone), then ASO begins to assign non-synchronized reserve priced at $0.00. If it is not enough to satisfy the 1,300 MW synchronized reserve requirement, then synchronized reserve and non-zero priced non-synchronized reserve are scheduled at a price dictated by the optimized supply curve. Non-synchronized reserve can often be scheduled at zero price but when scheduled it is constrained to remain off-line and available for the hour. As LMPs rise this could involve LOC. ASO will always choose synchronized reserve over equally priced non-synchronized reserve. In 159 hours between October 1 and December 31, 2012 the Non-Synchronized Reserve Market cleared at greater than $0.00. Figure 9-8 shows that non-synchronized reserve only clears when synchronized reserve also clears.

Shortage Pricing

On October 1, 2012 PJM introduced shortage 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.

Geography

As can be seen from Figure 9-7, the geography of the Synchronized Reserve Market has changed with Shortage Pricing. The former Southern Zone (Dominion) and RFC zone are now merged into the RTO Zone. Within the RTO Zone the Mid-Atlantic Dominion Sub-zone is defined by the most restrictive interface to the RTO and includes the former Mid-Atlantic Zone and Dominion.

Operation

In addition to the geographic changes, the market solution methodology changed significantly.[36] Reserves, regulation, and energy are jointly optimized and committed by the new Ancillary Services Optimizer (ASO) 60 minutes before the hour based on least cost using the LMP forecast. No price is calculated by the ASO. In addition to the ASO an Intermediate Term Security Constrained Economic Dispatch (IT SCED) runs with a one to two hour look-ahead optimizing a joint energy and reserves solution for every 15 minute period, commits incremental energy resources (the energy three-pivotal supplier test is run by the IT-SCED), and recommends incremental reserve resources which can be committed by PJM dispatch.

In addition, a Real-Time Security Constrained Economic Dispatch (RT SCED) joint optimizer with a 10-20 minute look-ahead uses the current state estimator solution and forecasts the load during its look-ahead period. Using its calculated Tier 1 and available (flexible) Tier 2 RT SCED redispatches energy and reserves among on-line dispatchable reserves (known as flexible reserves) to minimize the total cost of energy and reserves (both synchronized reserves and non-synchronized reserves).

Finally, a Locational Pricing Calculator (LPC) runs every five minutes and provides real-time pricing based on the currently approved RT-SCED solution. The hourly market clearing price is the simple average of each five-minute LPC-calculated price. According to PJM "In general, re-allocating reserve assignments to where they are most economic allows the most inexpensive generating capacity available to serve load while

36 See the *2012 State of the Market Report for PJM*, Volume II, Ancillary Service Markets Appendix, "Synchronized Reserve Market Clearing" for a more detailed description of the clearing methodology.

the more expensive online generators with lower opportunity costs provide reserves."[37]

Shortage Pricing Penalty Factors

The IT SCED, RT SCED, and LPC contain embedded penalty factors designed to allow them to optimally redispatch flexible reserve resources between energy and reserve and to cap their merit order price at the penalty level for any/all locations where that shortage exists (Table 9-15). The penalty factor will increase each year and remain under review to ensure they allow PJM operators to utilize fully all system assets and they accurately reflect the value of each product and location under shortage conditions.

Table 9-15 Shortage Pricing penalty factors: June 2012 through May 2016

Start Date	End Date	Synchronized Reserve Penalty Factor ($/MWh)	Non-Synchronized Reserve Penalty Factor ($/MWh)
October 1, 2012	May 31, 2013	$250	$250
June 1, 2013	May 31, 2014	$400	$400
June 1, 2014	May 31, 2015	$550	$550
June 1, 2015		$850	$850

When a shortage occurs for a specific reserve product (RTO synchronized, RTO non-synchronized reserves, Mid-Atlantic Dominion synchronized, and/or Mid-Atlantic Dominion non-synchronized reserves) merit order prices for the product/location will be capped at the penalty factor for the duration of the shortage event. If warranted, the resource will be compensated at settlement time for its true cost for providing service. From October through December, 2012 no location experienced a reserve shortage.

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 merged into one zone, the RTO Synchronized Reserve Zone, with its requirements structured to satisfy both regional specifications. As with the former RFC Zone, deliverability across the most limiting constraint (currently Bedington-Black Oak) requires that the RTO Zone maintain a subzone. What had been the Mid-Atlantic subzone before October 1, 2012 is now called the Mid-Atlantic Dominion sub-zone. The Synchronized Reserve requirement remains the same as it did for the previous Mid-Atlantic sub-zone, 1,300 MW. The primary reserve requirements of the new Mid-Atlantic Dominion sub-zone are now 1,700 MW.

PJM has established the RTO Synchronized Reserve Zone hourly requirement to be 150 percent of the largest contingency or 2,063 MW. This requirement can be changed in any hour when conditions (such as outages or maintenance) necessitate. These changes to the Synchronized Reserve requirement (sometimes called double spinning) are detailed below under "Demand." Since Shortage Pricing, PJM has declared the right to create additional zones or sub-zones within the synchronized reserve market with suitable notification of PJM stakeholders.[38]

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 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.

Shortage Pricing introduced another product and market: Non-Synchronized Reserve that can be used to fulfill the Primary Reserve requirement in both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion subzone subject to the limitation that at least 50 percent of primary reserve be synchronized.

Market Structure

Supply

For 2012, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remained significant. Demand side resources are relatively low cost, and their participation lowers overall Synchronized Reserve prices. PJM has limited the amount of DSR to

37 See "Shortage Pricing Update," <http://www.pjm.com/sitecore%20modules/web/~/media/committees-groups/committees/mrc/20121214-shortage/20121214-shortage-pricing-update.ashx>, (December 14, 2012).

38 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 74.

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 demand side resources decreased in 2012 over 2011 (from 982,434 MW to 737,951 MW). The DSR share of the total Synchronized Reserve Market increased from 17.7 percent in 2011 to 29.8 percent in 2012. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in 5.0 percent of hours in 2012 compared to 6.6 percent of hours in 2011. The merging of the former Mid-Atlantic subzone with Dominion into the new Mid-Atlantic Dominion subzone has made more Tier 1 reserve available to the subzone. The former Dominion Zone had an excess of Tier 1 lessening 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 1.4 for the Mid-Atlantic Dominion Subzone.[39] This is a 29.6 percent increase from 2011 when the ratio was 1.08. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of offered and eligible synchronized reserve to the required Tier 2 for all cleared Tier 2 hours in 2012 was 5.1 for the Mid-Atlantic Dominion Subzone. This is a 70 percent increase from 2011 when the ratio was 3.00. It is important to note however that the Mid-Atlantic Dominion Subzone is bigger than the Mid-Atlantic Subzone which was the basis for the 2011 metric. For the RTO Zone the offered and eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available.

Demand

With Shortage Pricing on October 1, 2012, PJM made a geographic change to the Synchronized Reserve Market footprint. The previous Southern Zone (Dominion) was merged into the previous Mid-Atlantic Sub-zone to become the Mid-Atlantic Dominion Sub-zone. The Synchronized Reserve requirement remains 1,300 MW but the primary reserve requirement (a combination of 10-minute synchronized reserve and 10-minute non-synchronized reserve) is set to 1,700 MW.

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 2012, in the RTO Synchronized Reserve Zone a Synchronized Reserve Market was cleared in two percent of hours. From January through September 2012 in the Mid-Atlantic Subzone a Tier 2 Synchronized Reserve Market was cleared in 69 percent of hours at an average of 448 MW. Between October and December in the Mid-Atlantic Dominion Subzone, a Tier 2 synchronized reserve market was cleared in 43 percent of hours, averaging 305 MW. For all of 2012, in the Mid-Atlantic/Mid-Atlantic Dominion Subzone, a Tier 2 synchronized reserve market was cleared in 62 percent of hours with 429 MW cleared, on average. Note that there is more Tier 1 MW available in the Mid-Atlantic Dominion Subzone after October, not only because of its integration with Dominion, but also because the transfer capability for Tier 1 from the RTO Zone into the Mid-Atlantic Subzone is set to 100 percent.

As of December 31, 2012, 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.

Table 9-16 Synchronized Reserve Market required MW, RTO Zone and Mid-Atlantic Dominion Subzone, December 2008 through December 2012

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	Dec 31, 2012	1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012	Dec 31, 2012	1,375

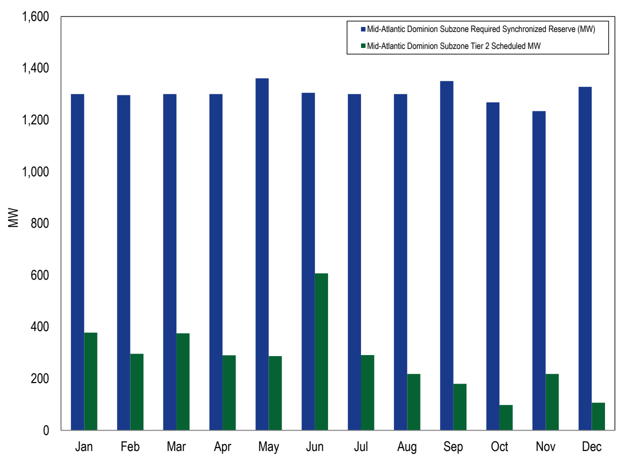
The market demand for Tier 2 synchronized reserve in the Mid-Atlantic Dominion sub-zone is determined by subtracting the amount of forecast Tier 1 synchronized reserve available plus the amount of Tier 1 available from the RTO Zone across the most limiting constraint (currently Bedington-Black Oak) from 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.

39 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.

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The requirement in the Mid-Atlantic Subzone was raised to 1,700 MW for several hours in May and June. The requirement in the Mid-Atlantic Subzone was also raised to 1,350 MW for several hours in May. The requirement in the Mid-Atlantic Subzone was raised to 1,716 MW from September 24 through 28. A generator outage changed the requirement to 1,175 MW from October 24 through November 10. Another outage changed the requirement to 1,220 MW from November 10 through November 19.

Figure 9-9 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through December 2012, for the Mid-Atlantic Dominion Synchronized Reserve Market.

Figure 9-9 Mid-Atlantic Dominion Synchronized Reserve Subzone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through December 2012



The RTO Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RTO Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement. In October through December 2012, the RTO Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in 46 (2.1 percent) hours with an average SRMCP of $4.46. The Mid-Atlantic Dominion Subzone cleared a separate Tier 2 market in 43 percent of all hours during October through December, 2012 at a weighted SRMCP of $11.99.

For all of 2012, the Mid-Atlantic/Mid-Atlantic Dominion Sub-zone cleared a Tier 2 Synchronized Reserve Market in 62.5 percent of all hours at a weighted SRMCP of $8.02.

The actual synchronized reserve requirement for the Mid-Atlantic Subzone for January through September 2012 was usually 1,300 MW. For the Mid-Atlantic Dominion Subzone from October through December 2012 the requirement was also 1,300 MW. The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system.

The 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.[40] 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 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 October through December 2012 was 4672, which is defined as highly concentrated. For all of 2012 the HHI for the Mid-Atlantic/Mid-Atlantic Dominion Subzone was 3570 which is highly concentrated. The HHI for the Mid-Atlantic Subzone for 2011 was 2637. The largest hourly market share was 100 percent and 56 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 46 percent of all hours in 2011). Looking at flexible unit sector of the synchronized reserve market between October and December, 2012, the hourly average HHI (all hours in which a market was cleared

40 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 54 (October 1, 2012), p. 71.

and flexible units were part of the market) was 3651. For units comprising the inflexible sector the HHI was 1185.

In October through December, 2012, 17 percent of hours in the Mid-Atlantic Dominion Subzone failed the three pivotal supplier test (Table 9-17). For all of 2012, 22 percent of hours failed the three pivotal supplier test. For 2011, 63 percent of hours failed the three pivotal supplier test. 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.

Table 9-17 Synchronized Reserve market monthly three pivotal supplier results: 2010, 2011 and 2012

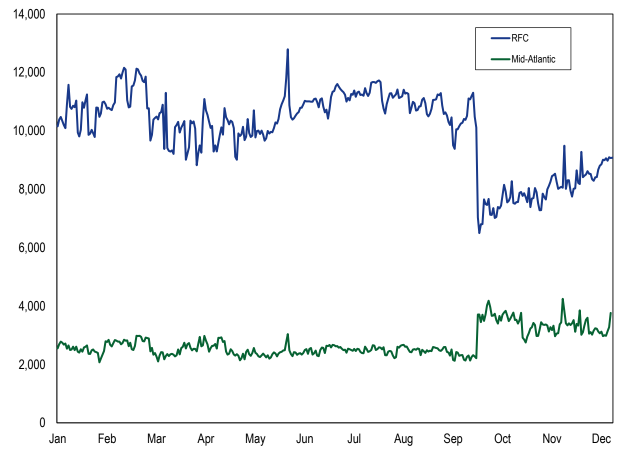
Month	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	45%	92%	64%
Feb	40%	99%	49%
Mar	38%	74%	65%
Apr	33%	83%	31%
May	15%	46%	45%
Jun	29%	14%	10%
Jul	10%	19%	23%
Aug	3%	25%	18%
Sep	4%	56%	17%
Oct	9%	73%	54%
Nov	17%	84%	83%
Dec	25%	88%	40%

Market Conduct

Offers

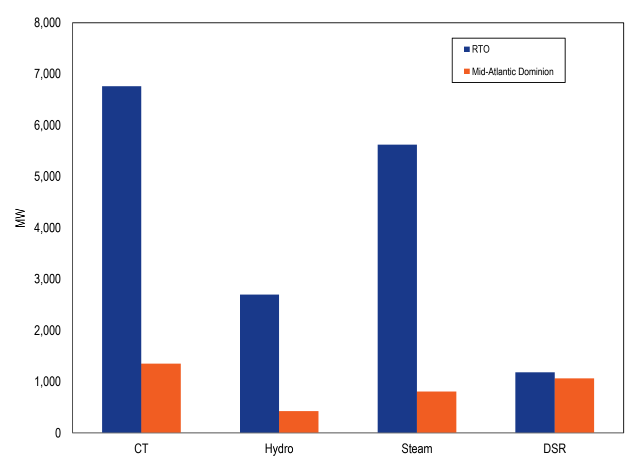
Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is 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 9-10 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.

Figure 9-10 Tier 2 synchronized reserve average hourly offer volume (MW): October through December 2012



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-11 shows average offer MW volume by market and unit type.

Figure 9-11 Average daily Tier 2 synchronized reserve offer by unit type (MW): October through December 2012



DSR

Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August, 2006. DSR has a significant impact on the Synchronized Reserve Market. As currently implemented in the Synchronized Reserve Market, DSR is always an inflexible resource. In October through December 2012, DSR was 36 percent of all cleared Tier 2 synchronized reserves, compared to 23 percent for the same period in

2011. In 3.5 percent of the hours in which synchronized reserve was cleared, all cleared MW were DSR (Table 9-18). In the hours when all cleared MW were DSR, the simple average SRMCP was $0.94. The simple average SRMCP for all cleared hours was $9.60.

Table 9-18 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through December 2010, 2011, 2012

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
2010	Jan	$5.84	$2.03	4%
2010	Feb	$5.97	$0.10	1%
2010	Mar	$8.45	$2.01	6%
2010	Apr	$7.84	$1.86	17%
2010	May	$9.98	$1.68	15%
2010	Jun	$9.61	$0.74	9%
2010	Jul	$16.30	$0.79	7%
2010	Aug	$11.17	$0.93	12%
2010	Sep	$10.45	$1.15	12%
2010	Oct	$8.21	$1.06	8%
2010	Nov	$9.59	$0.36	1%
2010	Dec	$12.49	$0.88	4%
2011	Jan	$10.75	$0.10	0%
2011	Feb	$10.91	NA	0%
2011	Mar	$11.34	$2.04	2%
2011	Apr	$16.07	$1.84	10%
2011	May	$10.59	$1.71	14%
2011	Jun	$13.41	$1.18	10%
2011	Jul	$16.99	$0.62	6%
2011	Aug	$10.62	$0.78	7%
2011	Sep	$10.97	$1.73	15%
2011	Oct	$9.65	$1.18	4%
2011	Nov	$10.39	$0.71	3%
2011	Dec	$10.04	$2.24	1%
2012	Jan	$6.25	$1.71	11%
2012	Feb	$5.37	$1.78	24%
2012	Mar	$6.55	$1.40	6%
2012	Apr	$6.62	$0.91	4%
2012	May	$8.24	$0.54	2%
2012	Jun	$4.25	$0.43	1%
2012	Jul	$14.92	$0.10	0%
2012	Aug	$5.63	$0.60	1%
2012	Sep	$5.72	$1.23	2%
2012	Oct	$16.15	$1.69	2%
2012	Nov	$11.44	$0.72	4%
2012	Dec	$5.06	$0.40	5%

Market Performance

Price

Figure 9-12 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 9-19 shows the monthly weighted average SRMCP, credits, and MW for the Mid-Atlantic Dominion subzone. The weighted average price for synchronized reserve in the Mid-Atlantic Dominion Subzone in 2012 was $8.02 while the corresponding cost of synchronized reserve was $12.71. Both price and cost are lower than in 2011, when price was $11.81 and cost was $15.48.

Table 9-19 Mid-Atlantic Dominion Sub-zone weighted synchronized reserve market clearing prices, credits, and MWs: 2012

Month	Weighted Synchronized Reserve Market Clearing Price	Synchronized Reserve Credits	PJM Scheduled MW	PJM Added MW	Self Scheduled MW
Jan	$6.25	$911,823	229,958	12,604	48,393
Feb	$5.37	$676,438	165,304	9,255	36,819
Mar	$6.55	$827,316	238,999	5,126	43,546
Apr	$6.62	$519,409	214,213	4,527	857
May	$8.24	$1,323,561	162,029	10,177	32,673
Jun	$4.25	$926,120	308,701	8,833	62,627
Jul	$14.92	$2,085,816	182,230	24,704	10,497
Aug	$5.63	$1,063,661	117,050	22,156	26,030
Sep	$5.72	$1,027,975	128,290	3,363	1,175
Oct	$16.15	$2,238,592	94,866	NA	7,204
Nov	$11.44	$3,719,841	175,093	NA	974
Dec	$5.06	$1,034,280	84,734	NA	935
Total	$8.02	$16,354,832	2,101,467	100,745	271,730

The RFC Synchronized Reserve requirement was satisfied by Tier 1 in all but six hours of January through September 2012. On October 1, 2012, the RFC Synchronized Reserve Zone became the RTO Reserve Zone. The Synchronized Reserve and Primary Reserve Requirements were satisfied by a combination of Tier 1 and non-synchronized reserve in all but 46 hours from October 1, 2012 through December 31, 2012. In the 46 hours when synchronized reserve was needed to fill the synchronized reserve and/or primary reserve requirement the maximum clearing price was $29.16 and the average clearing price was $4.46.

The Southern Synchronized Reserve Zone cleared a market in 94 hours of January through September 2012 with a weighted average clearing price of $20.47. The Southern Synchronized Reserve Zone was merged into the Mid-Atlantic Dominion Reserve Sub-Zone on October 1, 2012.

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 2012, the price of Tier 2 synchronized reserves was 63 percent of the cost.

Figure 9-12 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through December 2012

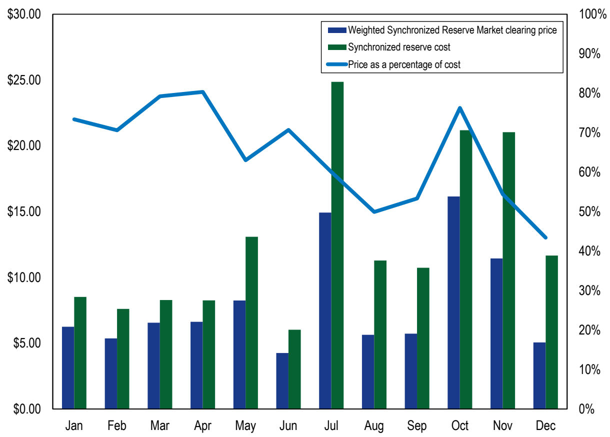


Table 9-20 shows the price and cost history of the Synchronized Reserve Market since 2005.

Table 9-20 Comparison of yearly weighted average price and cost for PJM Synchronized Reserve, 2005 through 2012

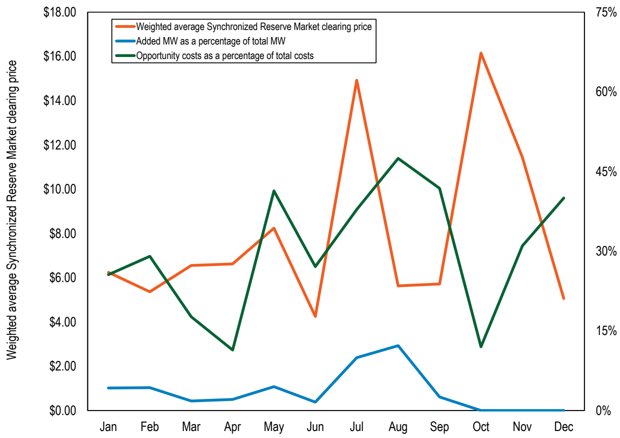
Year	Simple Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$10.89	$13.29	$17.59	76%
2006	$10.67	$14.57	$21.65	67%
2007	$11.57	$11.22	$16.26	69%
2008	$7.76	$10.65	$16.43	65%
2009	$6.58	$7.75	$9.77	79%
2010	$8.49	$10.55	$14.41	73%
2011	$9.48	$11.81	$15.48	76%
2012	$6.73	$8.02	$12.71	63%

The primary reason for the relatively low actual price to cost ratio is the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, the low price to cost ratio is in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers need the reserves for reliability reasons (Table 9-13). This practice is changing as a result of shortage pricing. The percentage of settled Tier 2 MW that was added by PJM dispatchers from January through September 2012, after market clearance was 6.4 percent (Table 9-21) (it was 3.2 percent in January through September 2011, 5.2 percent in January through September 2010, 11.6 percent in January through September 2009, and 68.8 percent in January through September 2008).

Table 9-21 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Dominion Subzone: 2012

Month	Added MW	Self Scheduled MW	Tier 2 Plus DSR Cleared MW
Jan	12,580	47,259	231,919
Feb	9,035	35,176	162,598
Mar	5,126	42,423	240,465
Apr	4,527	1,249	209,288
May	10,177	32,293	162,211
Jun	7,060	63,007	310,072
Jul	23,971	10,307	181,155
Aug	22,536	22,800	117,611
Sep	3,363	1,175	126,659
Oct	NA	7,204	94,866
Nov	NA	974	175,093
Dec	NA	935	84,734

Figure 9-13 Impact of Tier 2 synchronized reserve added MW to the Mid-Atlantic Dominion Sub-Zone: 2012



Tier 1 bias means the manual subtraction from (or addition to) the Tier 1 estimate that the market software uses to determine how much Tier 2 MW to buy. In 2010, PJM significantly increased its use of Tier 1 bias in market solutions. By subtracting from the estimated Tier 1 MW, PJM Market Operations forces the market software to purchase more Tier 2 MW than it estimates it needs. This reduces the need for PJM Dispatch to add Tier 2 MW after market clearance but means purchasing more Tier 2 MW than the market clearing software estimates it needs. There are several reasons for Tier 1 biasing. Sometimes units do not achieve the ramp rate they have bid, sometimes units fail to follow PJM dispatch, sometimes system conditions change rapidly during the hour between a market solution and the actual hour.

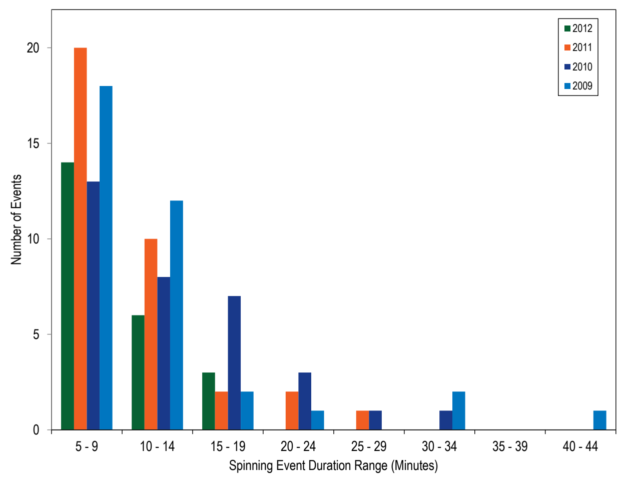
Beginning with Shortage Pricing on October 1, 2012, PJM expanded its use of biasing. Tier 1 biasing can be applied to the intermediate term SCED solution, or the real time SCED solution, to the ASO solution. RT SCED Tier 1 biasing occurred between October 19 and October 26 for a total of 97 hours averaging 220 MW of bias. IT SCHED Tier 1 biasing was used 383 hours between October 19 and December 2 with an average bias of 519 MW. ASO Tier 1 biasing was used 152 hours between November 10 and December 23 with an average ASO Tier 1 bias of 364 MW.

The MMU recommends that PJM define explicit and transparent rules for calculating available Tier 1 MW and for its use of biasing during any phase of the market solution. Additionally, the MMU recommends that PJM publish these rules in Manual 11: Energy and Ancillary Services Market Operations, and associate each instance of biasing with a rule.

History of Spinning Events

Spinning events (Table 9-22) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load synchronized reserve.[41] The reserve remains loaded until system balance is recovered. From January 2009 through December 2012, PJM experienced 127 spinning events, or almost three events per month. Spinning events generally lasted between 7 minutes and 20 minutes with an average length of 11.4 minutes, although several events have lasted longer than 30 minutes.

Figure 9-14 Spinning events duration distribution curve, 2009 to 2012



41 See PJM. "Manual 12, Balancing Operations," Revision 27 (December 20, 2012), pp. 36-37.

Table 9-22 Spinning Events, January 2009 through December 2012

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-17-2009 09:37	RFC	7	FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9
JAN-20-2009 17:33	RFC	10	MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8
JAN-21-2009 11:52	RFC	9	MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8
FEB-18-2009 18:38	Mid-Atlantic	10	APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9
FEB-19-2009 11:01	RFC	6	APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6
FEB-28-2009 06:19	RFC	5	MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10
MAR-03-2009 05:20	Mid-Atlantic	11	MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9
MAR-05-2009 01:30	Mid-Atlantic	43	MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8
MAR-07-2009 23:22	RFC	11	JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16
MAR-23-2009 23:40	Mid-Atlantic	10	JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7
MAR-23-2009 23:42	RFCNonMA	8	JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7
MAR-24-2009 13:20	Mid-Atlantic	8	JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7
MAR-25-2009 02:29	RFC	9	JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18
MAR-26-2009 13:08	RFC	10	JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10
MAR-26-2009 18:30	Mid-Atlantic	20	AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12
APR-24-2009 16:43	RFC	11	AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7
APR-26-2009 03:04	Mid-Atlantic	5	AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10
MAY-03-2009 15:07	RFC	10	AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19
MAY-17-2009 07:41	RFC	5	SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14
MAY-21-2009 21:37	RFC	13	SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12
JUN-18-2009 17:39	RFC	12	OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9
JUN-30-2009 00:17	Mid-Atlantic	8	OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7
JUL-26-2009 19:07	RFC	18	OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5
JUL-31-2009 02:01	RFC	6	OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10			
AUG-15-2009 21:07	RFC	17	OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12			
SEP-08-2009 10:12	Mid-Atlantic	8	NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6			
SEP-29-2009 16:20	RFC	7	NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6			
OCT-01-2009 10:13	RFC	11	DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5			
OCT-18-2009 22:40	Mid-Atlantic	8	DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7			
OCT-26-2009 01:01	RFC	7	DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8			
OCT-26-2009 11:05	RFC	13	DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7			
OCT-26-2009 19:55	RFC	8	DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9			
NOV-20-2009 15:30	RFC	8	DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10			
DEC-09-2009 22:34	Mid-Atlantic	34				DEC-15-2011 14:35	Mid-Atlantic	8			
DEC-09-2009 22:37	RFCNonMA	31				DEC-21-2011 14:26	RFC	18			
DEC-14-2009 11:11	Mid-Atlantic	8									

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 deficits in January through September 2012. Since shortage pricing on October 1, 2012, PJM allows some units to transition between synchronized reserve and energy on a five-minute basis within an operating hour. This additional flexibility is designed to minimized overall costs of energy and reserve and reduces the chance of a synchronized reserve shortage. A primary reserve shortage can occur triggering shortage pricing. No primary reserve shortages occurred between October 1, 2012 and December 31, 2012.

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.[42]

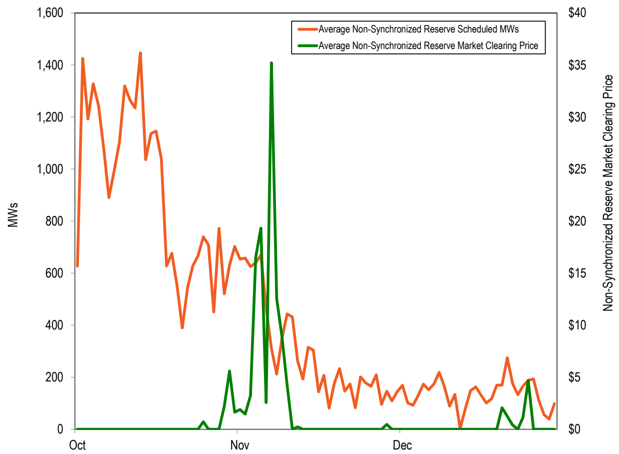
Like Tier 1 synchronized reserve PJM calculates the amount of non-synchronized reserve available each

42 PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 57 (December 1, 2012), p. 85.

hour. The calculation is based upon a unit's startup and notification time, energy ramp rate, and economic minimum. 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 9-15 shows the daily average non-synchronized reserve market clearing price and average scheduled MW. The Mid-Atlantic Dominion Reserve Zone non-synchronized reserve market clearing price was greater than zero in 20 hours in October (all after October 24), 121 hours in November, 2012, and 18 hours in December (all between December 22 and December 26). The non-synchronized reserve market clearing price for the RTO Reserve Zone was greater than zero in only three hours in October through December, 2012.

Figure 9-15 Daily average Non-Synchronized Reserve Market clearing price and MW cleared: October through December 2012



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.[43]

The DASR 30-minute reserve requirements are determined by the reliability region.[44] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[45] 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 2012, the required DASR was 7.03 percent of peak load forecast, down from 7.11 percent in 2011.[46] The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2011 the load forecast error increased from 1.90 percent to 1.97 percent. The forced outage rate decreased from 4.98 percent to 4.93 percent. Added together, the 2012 DASR requirement was 7.03 percent. The DASR MW purchased averaged 6,841 MW per hour for 2012, an increase from 6,500 MW per hour in 2011. DASR MW purchased increased by 5.1 percent in 2012 over the 2011, from 57.0 million MW to 59.9 million MW.

In 2012, no hours failed the three pivotal supplier test in the DASR Market. Twenty one hours failed the pivotal supplier test in 2011.

Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR, but remained insignificant. No demand side resources cleared the DASR market in 2012.

43 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
44 PJM. "Manual 13, Emergency Requirements," Revision 52 (February 1, 2013), pp. 12-13.
45 PJM. "Manual 10, Pre-Scheduling Operations," Revision 27 (February 28, 2013), pp. 18-19.
46 See the *2011 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.[47] 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 December 31, 2012, twelve 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

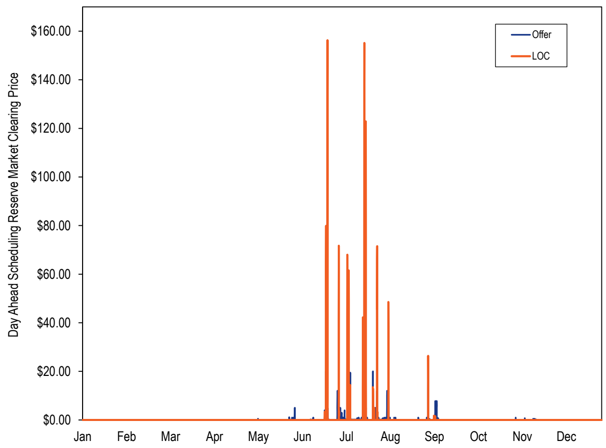
Table 9-23 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through December 2011 and 2012

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR Credits
2011	Jan	6,536	$0.00	$1.00	$0.03	$127,837
2011	Feb	6,180	$0.00	$1.00	$0.02	$61,682
2011	Mar	5,720	$0.00	$1.00	$0.01	$45,885
2011	Apr	5,265	$0.00	$0.05	$0.01	$24,463
2011	May	5,554	$0.00	$25.52	$0.29	$894,607
2011	Jun	7,305	$0.00	$193.97	$2.26	$9,653,815
2011	Jul	8,647	$0.00	$217.12	$4.21	$22,880,723
2011	Aug	7,787	$0.00	$61.91	$0.75	$3,577,433
2011	Sep	6,535	$0.00	$5.00	$0.07	$292,252
2011	Oct	5,874	$0.00	$0.04	$0.00	$3,655
2011	Nov	6,067	$0.00	$0.04	$0.00	$6,155
2011	Dec	6,532	$0.00	$0.21	$0.00	$6,181
2012	Jan	6,944	$0.00	$0.02	$0.00	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	$540,586
2012	Oct	6,022	$0.00	$0.04	$0.00	$5,878
2012	Nov	6,371	$0.00	$1.00	$0.02	$75,561
2012	Dec	6,526	$0.00	$0.05	$0.00	$5,975

For 82 percent of hours in 2012, DASR cleared at a price of $0.00 (Figure 9-16). For all of 2012, the weighted DASR price was $0.57, a $0.02 increase from the weighted price during 2011. In 82 percent of hours in 2012, the DASR Market Clearing Price was $0.00; however, there were several days of extremely high DASR prices in June, July and August (a maximum price of $156.29 occurred on June 21, 2012). These high prices were primarily the result of high demand and limited supply which created the need for redispatch in the Day-Ahead Energy Market in order to provide DASR. The result was that DASR prices in these hours reflected opportunity costs associated with the redispatch. 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. Most (98 percent) DASR clearing prices consist solely of the offer price. For a few of the high price hours the price is composed almost entirely of LOC. For the top 0.5 percent (average clearing price = $73.93) of hours, on average 97.2 percent of the price is determined by opportunity cost. On the other hand, for the bottom 99.5 percent (average clearing price = $0.13) of hours, on average 8.8 percent of the price is composed of LOC (Figure 9-16).

47 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 57 (December 1, 2012), p. 141-142.

Figure 9-16 Hourly components of DASR clearing price: January through December 2012



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. PJM's goal is to charge transmission customers for black start service according to their zonal load ratio share (Table 9-24).

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.

The MMU has concerns that there is a disconnect between a service that is required for system reliability, the balkanized approach to procuring that service, and the need to secure voluntary participation in the system restoration plans from the relatively few potential providers at the critical locations identified. The current process provides for PJM and transmission owners to jointly develop and administer the black start service plan for each transmission zone. Following a stakeholder process in the System Restoration Strategy Task Force (SRSTF), substantial changes to the black start restoration and procurement strategy were introduced. PJM and the MMU's 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.

In 2012, black start charges were $50.2 million. This is 151 percent higher than 2011, when total black start service charges were $20.0 million. There was substantial zonal variation. Black start zonal charges in 2012 ranged from $0.02 per MW in the ATSI zone (total charges: $119,167) to $3.62 per MW in the AEP zone (total charges: $32,468,706).

The black start charges in Table 9-24 include estimated charges that were allocated to customers as operating reserve charges but that were in fact to pay for the operation of ALR black start units.[48]

48 See the *2012 State of the Market Report for PJM*, Section 3, "Operating Reserves", at "Operating Reserve Charges."

Table 9-24 Black start yearly zonal charges for network transmission use: 2012

Zone	Network Charges	Black Start Rate ($/MW)
AECO	$566,721	$0.52
AEP	$32,468,706	$3.62
AP	$208,617	$0.06
ATSI	$119,167	$0.02
BGE	$5,493,609	$2.07
ComEd	$4,238,804	$0.49
DAY	$199,751	$0.15
DEOK	$278,948	$0.14
DLCO	$45,806	$0.04
DPL	$533,673	$0.34
JCPL	$471,832	$0.20
Met-Ed	$504,209	$0.44
PECO	$1,254,077	$0.38
PENELEC	$453,764	$0.40
Pepco	$280,952	$0.11
PPL	$145,528	$0.05
PSEG	$2,945,488	$0.74

Table 9-25 shows new black start NERC critical infrastructure protection (CIP) capital costs being recovered by black start units in PJM. These costs were located in multiple zones, including ComEd, DEOK, DLCO, JCPL, Met-Ed, PENELEC and Pepco. These costs are recoverable through Schedule 6A of the tariff, and include both physical security and cyber security investments in order to protect black start units deemed critical. This included equipment necessary to restrict access to both physical sites, as well as firewall and software upgrades necessary protect cyber assets and monitor unit operations.

Table 9-25 Black start NERC CIP capital cost recovery in PJM: 2012

Capital Cost Requested	Cost Recovered in 2012	Number of Units	MW
$1,736,971	$150,290	33	678.1

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 a product 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. 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]

Overview

Marginal Loss Cost

Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. Losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal losses when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[4] The primary benefit of a marginal loss calculation is that it more accurately models the physical reality of power system losses, which permits increased efficiency and more optimal asset utilization. Marginal loss modeling creates a separate marginal loss price for every location on the power grid. This marginal loss price (MLMP) is a component of LMP that is charged to load and credited to generation.

Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[5] Unlike the other categories of marginal loss accounting, inadvertent loss charges are common costs not directly attributable to specific participants. Inadvertent loss charges are distributed to load on a load ratio basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

1 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) 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. ATSI is treated as part of MISO for the period from January 2011 through May 31, 2011 and as part of PJM for the period from June 1, 2011 through December 31,2012.

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 March 2, 2013, and are subject to change, based on continued PJM billing updates.

4 For additional information, see OATT Section 3.4.

5 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

Marginal loss costs can be positive or negative with respect to the reference bus. If an increase in load at a bus would decrease losses, the marginal loss component of LMP of that bus will be negative. If an increase in generation at a bus would result in an increase in losses, the marginal loss component of that bus will be negative. If an increase of load at a bus would increase losses, the marginal loss component of LMP at that bus will be positive. If an increase in generation at a bus results in a decrease of system losses, then the marginal loss component of LMP at that bus will be positive.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets priced at the marginal loss price component of LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

Marginal loss credits or loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total energy costs and net residual market adjustments, that is paid back in full to load and exports on a load ratio basis.

- **Total Marginal Loss Costs.** Total marginal loss costs in 2012 decreased by $397.9 million or 28.8 percent from 2011, from $1,379.6 million to $981.7 million. Day-ahead net marginal loss costs in 2012 decreased by $426.8 million or 29.8 percent from 2011, from $1,430.5 million to $1,003.8 million. Balancing net marginal loss costs increased in 2012 by $28.9 million or 56.7 percent from 2011, from -$51.0 million to -$22.1 million.[6]
- **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 2012 ranged from $51.0 million in April to $143.4 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 that is paid back in full to load and exports on a load ratio basis.[7,8] The marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 million.
- **Zonal Total Marginal Loss Costs.** In 2012, zonal total marginal loss costs ranged from $2.1 million in RECO to $205.9 million in AEP. Compared to 2011, 2012 had a decrease in total marginal loss costs across the PJM control zones, except the ATSI control zone, which had an increase.[9]

Congestion Cost

Total congestion costs equal net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. Net implicit congestion costs equal load congestion payments minus generation

6 Total marginal loss costs in PJM in 2012 also changed due to the addition of the DEOK Control Zone, which accounted for $3.2 million or 0.3 percent of the total marginal loss costs. The ATSI Control Zone had an increase in total marginal loss cost in 2012 because it became part of PJM on June 1, 2011, which left the first five months of 2011 out of the 2011 total marginal loss cost for ATSI.

7 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

8 Net residual market adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Net residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MW.

9 See the *2012 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses," at "Zonal Marginal Loss Costs."

congestion credits. Net explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. Net inadvertent congestion charges are the congestion costs associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour. Unlike the other categories of congestion cost accounting, inadvertent congestion charges are common costs not directly attributable to specific participants. Inadvertent congestion charges are distributed to load on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

Congestion charges can be both positive and negative. When a constraint binds, the price effects of that constraint vary. The system marginal price (SMP) is uniform for all areas, while the congestion components of Locational Marginal Price (LMP) will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[10]

Day-ahead congestion charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing congestion charges and credits are based on load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where real-time LMP has a positive congestion component, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative congestion component, negative balancing congestion costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result.

10 The SMP is the price at the distributed load reference bus.

- **Total Congestion.** Total congestion costs decreased by $470.0 million or 47.0 percent, from $999.0 million in 2011 to $529.0 million in 2012.[11] Day-ahead congestion costs decreased by $465.1 million or 37.4 percent, from $1,245.0 million in 2011 to $779.9 million in 2012. Balancing congestion costs decreased by $4.9 million or 2.0 percent from -$246.0 million in 2011 to -$250.9 million in 2012.
- **Monthly Congestion.** Significant monthly fluctuations in congestion costs were the result of changes in load and energy import levels, changes in the dispatch of generation and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2012 ranged from $24.9 million in October to $73.1 million in July.
- **Geographic Differences in CLMP.** Differences in CPLM among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the Graceton – Raphael Road line, the Woodstock flowgate (reciprocally coordinated between PJM and MISO), West Interface, and the Bedington – Black Oak interface. (Table 10-27)
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2012.[12] Day-ahead congestion frequency increased by 60.3 percent from 155,670 congestion event hours in 2011 to 249,572 congestion event hours in 2012. Day-ahead, congestion-event hours decreased on internal PJM interfaces but increased on transmission lines, transformers and reciprocally coordinated flowgates between PJM and the MISO.

  Real-time congestion frequency decreased by 7.1 percent from 22,513 congestion event hours in 2011 to 20,917 congestion event hours in 2012. Real-time, congestion-event hours decreased on the internal PJM interfaces and transformers, but increased on transmission lines and reciprocally coordinated flowgates between PJM and MISO.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In

11 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change.

12 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.

2012, for only 3.2 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In 2012, for 38.3 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 2012. With $68.5 million in total congestion costs, it accounted for 16.1 percent of the total PJM congestion costs in 2012. The top five constraints in terms of congestion costs together contributed $177.0 million, or 41.6 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South interface, the West interface, the Bedington - Black Oak interface, the Woodstock flowgate (a reciprocally coordinated flowgate between PJM and MISO) and the Graceton - Raphael Road line.

- **Zonal Congestion.**[13] ComEd was the most congested zone in 2012.[14] ComEd had -$334.2 million in total load costs, -$521.6 million in total generation credits and -$16.4 million in explicit congestion, resulting in $171.0 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 transmission line, Woodstock flowgate, Rantoul - Rantoul Jct flowgate, Oak Grove – Galesburg flowgate and the Prairie State - W Mt. Vernon flowgate contributed $81.0 million, or 47.4 percent of the total ComEd Control Zone congestion costs.

  The AEP Control Zone was the second most congested zone in PJM in 2012, with $104.2 million. The Monticello - East Winamac flowgate contributed $12.4 million or 11.9 percent of the total AEP Control Zone congestion cost in 2012. The Dominion Control Zone was the third most congested zone in PJM in 2012, with a cost of $63.3 million.

- **Ownership.** In 2012, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2012, financial companies received $83.1 million in net congestion credits, a decrease of $91.6 million or 52.4 percent compared to 2011. In 2012, physical companies paid $612.1 million in net congestion charges, a decrease of $561.5 million or 47.8 percent compared to 2011.

Conclusion

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 have been decreasing since 2010, due to decreases in LMP and decreases in fuel costs. Total marginal loss costs decreased in 2012 by $397.9 million or 28.8 percent from 2011, from $1,379.6 million to $981.7 million.

Marginal loss credits are distributed to load and exports. Marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 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. Total congestion costs decreased by $470.0 million or 47.0 percent, from $999.0 million in 2011 to $529.0 million in 2012. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 planning period. In the first seven months of the 2012 to 2013 planning period, total ARR and FTR revenues offset 82.1 percent of the congestion costs. FTRs were paid at 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 74.9 percent of the target allocation level for the first seven months of the 2012 to 2013 planning

13 Tables reporting zonal congestion have been moved from this section of the report to Appendix G. See the *2012 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses."

14 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change. As of March 2, 2013, the total zonal congestion related numbers presented here differed from the March 2, 2013 PJM totals by $0.10 Million, a discrepancy of 0.02 percent (.00019).

period.[15] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

Locational Marginal Price (LMP)

Components

As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. There are no congestion or losses included in the load weighted reference bus price, unlike the case with a single node reference bus.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus is made up of three components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product 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 incremental considerations of losses and transmission constraints. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[16] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[17] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the years 2009 to 2012. The load-weighted average real-time LMP decreased $10.71 or 23.3 percent from $45.94 in 2011 to $35.23 in 2012. The load-weighted average congestion component decreased $0.01 or 26.9 percent from $0.05 in 2011 to $0.04 in 2012. The load-weighted average loss component decreased $0.01 or 26.9 percent from $0.02 in 2011 to $0.01 in 2012. The load-weighted average energy component decreased $10.69 or 23.3 percent from $45.87 in 2011 to $35.18 in 2012.

Table 10-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2009 through 2012

Year	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01

In the Real-Time Energy Market, the distributed load reference bus is weighted by system estimates of the load in real time. At the time the LMP is determined in the Real-Time Energy Market, the energy component equals the system load-weighted price. However, real-time bus-specific loads are adjusted, after the fact, according to updated information from meters. This meter adjusted load is accounting load that is used in settlements and forms the basis of the reported PJM load weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM-wide real-time load-weighted LMP is due to the difference between estimated and meter corrected loads used to weight the load-weighted reference bus and the load-weighted LMP.

15 See the *2012 State of the Market Report for PJM* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013"

16 For additional information, see the MMU Technical Reference for PJM Markets, at "Marginal Losses."

17 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.

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for 2009 through 2012. The load-weighted average day-ahead LMP decreased $10.64 or 23.5 percent from $45.19 in 2011 to $34.55 in 2012. The load-weighted average congestion component increased $0.17 or 276.8 percent from -$0.06 in 2011 to $0.11 in 2012. The load-weighted average loss component increased $0.14 or 90.7 percent from -$0.15 in 2011 to -$0.01 in 2012. The load-weighted average energy component decreased $10.94 or 24.1 percent from $45.40 in 2011 to $34.46 in 2012. In terms of proportion of day-ahead LMP, the congestion and loss components both increased, while the energy component became a smaller proportion in 2012.

Table 10-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2009 through 2012

Year	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)

In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed demand weighted price. The day-ahead weighted system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price. However, in the Day-Ahead Energy Market the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP is due to the difference in the types of demand used to weight the load-weighted reference bus and the load-weighted LMP.

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 10-3 for 2011 and 2012. The day-ahead components of LMP for each control zone are presented in Table 10-4 for years 2011 and 2012.

Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2011 and 2012

	2011				2012			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$53.11	$46.83	$3.92	$2.37	$37.55	$35.86	$0.23	$1.46
AEP	$40.92	$45.26	($2.91)	($1.43)	$33.15	$34.73	($0.75)	($0.83)
AP	$45.49	$45.56	$0.06	($0.13)	$34.86	$34.91	$0.04	($0.09)
ATSI	$42.09	$44.59	($2.32)	($0.18)	$34.42	$34.99	($0.78)	$0.21
BGE	$54.27	$46.40	$5.74	$2.14	$40.03	$35.44	$2.99	$1.59
ComEd	$36.20	$45.77	($6.93)	($2.64)	$31.76	$35.39	($2.05)	($1.58)
DAY	$41.78	$45.94	($3.40)	($0.75)	$34.25	$35.14	($0.95)	$0.05
DEOK	NA	NA	NA	NA	$32.67	$35.16	($0.87)	($1.62)
DLCO	$41.31	$45.73	($2.98)	($1.45)	$33.53	$35.05	($0.47)	($1.05)
Dominion	$50.59	$46.45	$3.54	$0.60	$37.28	$35.45	$1.48	$0.35
DPL	$52.20	$46.54	$3.05	$2.60	$39.53	$35.53	$2.31	$1.68
JCPL	$53.48	$47.22	$3.88	$2.37	$37.34	$35.92	$0.09	$1.33
Met-Ed	$49.51	$45.82	$2.87	$0.82	$36.30	$35.11	$0.67	$0.53
PECO	$50.83	$46.16	$3.05	$1.62	$36.78	$35.27	$0.61	$0.89
PENELEC	$45.12	$44.98	($0.25)	$0.38	$35.10	$34.66	($0.12)	$0.56
Pepco	$51.84	$46.47	$4.17	$1.20	$39.08	$35.47	$2.68	$0.93
PPL	$49.31	$45.57	$2.99	$0.75	$35.44	$34.92	$0.00	$0.52
PSEG	$52.68	$46.36	$3.96	$2.35	$37.48	$35.38	$0.71	$1.39
RECO	$49.66	$47.48	$0.02	$2.16	$37.80	$36.09	$0.42	$1.29
PJM	$45.94	$45.87	$0.05	$0.02	$35.23	$35.18	$0.04	$0.01

Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2011 and 2012

	2011				2012			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$53.09	$46.58	$3.78	$2.74	$37.36	$35.08	$0.66	$1.62
AEP	$41.12	$45.12	($2.39)	($1.61)	$32.71	$34.19	($0.51)	($0.97)
AP	$45.10	$45.08	$0.10	($0.09)	$34.29	$34.26	$0.09	($0.06)
ATSI	$41.89	$44.76	($1.83)	($1.04)	$33.55	$34.32	($0.69)	($0.08)
BGE	$53.21	$46.11	$4.57	$2.53	$39.55	$34.85	$2.76	$1.93
ComEd	$35.72	$45.16	($6.17)	($3.28)	$30.72	$34.60	($1.98)	($1.90)
DAY	$41.54	$45.64	($3.21)	($0.89)	$33.76	$34.58	($0.65)	($0.16)
DEOK	NA	NA	NA	NA	$32.18	$34.45	($0.49)	($1.79)
DLCO	$40.98	$45.35	($2.94)	($1.43)	$33.05	$34.42	($0.30)	($1.07)
Dominion	$49.78	$46.13	$2.97	$0.68	$36.56	$34.76	$1.31	$0.48
DPL	$52.62	$46.24	$3.40	$2.97	$38.91	$34.94	$1.86	$2.11
JCPL	$52.22	$46.47	$3.08	$2.67	$37.03	$35.10	$0.47	$1.47
Met-Ed	$48.62	$45.08	$2.74	$0.80	$35.44	$34.29	$0.50	$0.65
PECO	$51.11	$45.66	$3.43	$2.01	$36.40	$34.62	$0.72	$1.06
PENELEC	$44.35	$44.35	($0.25)	$0.24	$34.69	$33.95	$0.12	$0.62
Pepco	$51.03	$45.49	$3.90	$1.64	$38.26	$34.58	$2.39	$1.29
PPL	$48.69	$45.23	$2.79	$0.67	$34.82	$34.22	$0.12	$0.48
PSEG	$52.23	$45.96	$3.53	$2.75	$37.25	$34.81	$0.79	$1.65
RECO	$49.96	$46.39	$1.48	$2.10	$36.91	$35.20	$0.34	$1.36
PJM	$45.19	$45.40	($0.06)	($0.15)	$34.55	$34.46	$0.11	($0.01)

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 (SMP). Total energy costs, analogous to total congestion costs, are equal to the net of the load energy payments minus generation energy credits, plus explicit energy costs, plus inadvertent energy charges, incurred in both the Day-Ahead Energy Market and the balancing energy market. 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.

- **Day-Ahead Load Energy Payments.** Day-ahead, load energy payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales are equivalent to demand.) Day-ahead, load energy payments are calculated using MW and the load bus energy component of LMP (energy LMP), the decrement bid energy LMP or the energy LMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Energy Credits.** Day-ahead, generation energy credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases are equivalent to generation.) Day-ahead, generation energy credits are calculated using MW and the generator bus energy LMP, the increment offer energy LMP or the energy LMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Energy Payments.** Balancing, load energy payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load energy payments are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.
- **Balancing Generation Energy Credits.** Balancing, generation energy credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation energy credits are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.
- **Explicit Energy Costs.** Explicit energy costs are the net energy costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and energy LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit energy costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time energy LMP at the transactions' sources and sinks. The explicit energy costs will sum to zero because the LMP (SMP) at the transactions' sources and sinks will be the same for each transaction.
- **Inadvertent Energy Charges.** Inadvertent energy charges are the net energy charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent energy charges are common costs, not directly attributable to specific participants, which are distributed on a load ratio basis.[18]

Total Energy Costs

Table 10-5 shows total energy, loss and congestion component costs and total PJM billing, for each year from 2009 through 2012. The total energy, loss and congestion component costs appear low compared to total PJM billing because these totals are actually net energy, loss and congestion costs.

18 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

Table 10-5 Total PJM costs by component (Dollars (Millions)): 2009 through 2012[19]

	Component Costs (Millions)					
	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($629)	$1,268	$719	$1,358	$26,550	5.1%
2010	($798)	$1,635	$1,424	$2,261	$34,771	6.5%
2011	($794)	$1,380	$998	$1,584	$35,887	4.4%
2012	($593)	$982	$529	$926	$29,181	3.2%

Table 10-6 Total PJM energy costs by category (Dollars (Millions)): 2009 through 2012

	Energy Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,480.9	$0.0	$28.3	($793.7)
2012	$37,471.4	$38,073.5	$0.0	$9.1	($593.0)

Energy costs for 2009 through 2012 are shown in Table 10-6 and Table 10-7. Table 10-6 shows PJM energy costs by category for 2009 through 2012 and Table 10-7 shows PJM energy costs by market category for 2009 through 2012. These energy costs are the actual total energy costs rather than the net energy costs in Table 10-5.

Table 10-7 Total PJM energy costs by market category (Dollars (Millions)): 2009 through 2012

	Energy Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.8)	$28.3	($793.7)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.8)	($177.6)	$0.0	$7.8	$9.1	($593.0)

Monthly Energy Costs

Table 10-8 shows a monthly summary of energy costs by type for 2011 and 2012.

Table 10-8 Monthly energy costs by type (Dollars (Millions)): 2011 and 2012

	Energy Costs (Millions)							
	2011				2012			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($90.3)	($5.2)	$2.1	($93.3)	($48.5)	($10.1)	$2.5	($56.1)
Feb	($61.1)	($2.4)	$2.3	($61.2)	($36.0)	($9.9)	$2.4	($43.5)
Mar	($52.4)	($5.4)	$2.4	($55.4)	($30.1)	($8.6)	$1.9	($36.8)
Apr	($49.9)	($0.3)	$2.5	($47.7)	($30.7)	($2.8)	$0.7	($32.8)
May	($54.8)	($0.2)	$2.9	($52.1)	($39.4)	$0.1	($0.3)	($39.6)
Jun	($82.1)	($3.2)	$1.1	($84.2)	($57.1)	$4.0	$0.0	($53.1)
Jul	($110.0)	($16.8)	$6.7	($120.1)	($84.0)	$3.0	$0.6	($80.4)
Aug	($66.9)	($16.4)	$5.0	($78.2)	($60.3)	$2.6	$0.3	($57.4)
Sep	($55.0)	($5.5)	$1.5	($59.0)	($43.6)	$1.1	($0.2)	($42.8)
Oct	($42.7)	($5.9)	$0.3	($48.3)	($42.2)	$1.6	$0.2	($40.5)
Nov	($30.2)	($14.6)	$0.8	($44.0)	($65.2)	$7.8	$1.1	($56.2)
Dec	($39.7)	($11.0)	$0.6	($50.1)	($72.7)	$19.0	($0.1)	($53.8)
Total	($735.2)	($86.8)	$28.3	($793.7)	($609.9)	$7.8	$9.1	($593.0)

19 The Energy Costs, Loss Costs and Congestion Costs include net inadvertent charges.

Marginal Losses

Marginal Loss Accounting

PJM calculates marginal loss costs for each PJM member.

- **Day-Ahead Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus loss component of LMP (MLMP), the decrement bid MLMP or the MLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MWs and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[20]

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, plus inadvertent loss charges, 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.

Monthly marginal loss costs in 2012 ranged from $51.0 million in April to $143.4 million in July.

Marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 million.

Total Marginal Loss Costs

Table 10-9 shows the total marginal loss component costs for 2009 through 2012. The yearly total loss component costs appear low compared to total PJM billing because these totals are actually net loss costs.

20 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

Table 10-9 Total PJM Marginal Loss Component Costs (Dollars (Millions)): 2009 through 2012[21]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$1,268	NA	$26,550	4.8%
2010	$1,635	29.0%	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
2012	$982	(28.8%)	$29,181	3.4%

Total marginal loss costs for 2009 through 2012 are shown in Table 10-10 and Table 10-11. Table 10-10 shows PJM total marginal loss costs by category for 2009 through 2012. Table 10-11 shows PJM total marginal loss costs by market category for 2009 through 2012.

Table 10-10 Total PJM marginal loss costs by category (Dollars (Millions)): 2009 through 2012

	Marginal Loss Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($78.4)	($1,314.2)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.6
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7

Table 10-11 Total PJM marginal loss costs by market category (Dollars (Millions)): 2009 through 2012

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.4	($2.5)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.6
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7

Table 10-12 Monthly marginal loss costs by type (Dollars (Millions)): 2011 and 2012

	Marginal Loss Costs (Millions)							
	2011				2012			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$188.5	($2.9)	$0.0	$185.7	$100.6	($5.4)	$0.0	$95.2
Feb	$121.8	($1.8)	$0.0	$119.9	$80.4	($3.1)	$0.0	$77.2
Mar	$108.8	($4.8)	$0.0	$104.0	$67.1	($5.2)	$0.0	$61.9
Apr	$84.8	($5.6)	$0.0	$79.2	$55.4	($4.4)	$0.0	$51.0
May	$94.3	($7.0)	$0.0	$87.3	$69.6	($2.5)	($0.0)	$67.1
Jun	$129.9	($4.5)	$0.0	$125.4	$93.3	($0.8)	$0.0	$92.5
Jul	$217.4	($3.7)	$0.0	$213.7	$141.8	$1.6	$0.0	$143.4
Aug	$137.9	($3.5)	$0.0	$134.5	$96.1	$2.4	$0.0	$98.5
Sep	$107.7	($4.7)	$0.0	$102.9	$71.7	($0.9)	($0.0)	$70.8
Oct	$85.7	($3.6)	$0.0	$82.0	$65.9	($1.7)	$0.0	$64.1
Nov	$76.0	($1.7)	$0.0	$74.3	$83.0	($0.6)	$0.0	$82.5
Dec	$77.8	($7.1)	$0.0	$70.6	$78.8	($1.3)	$0.0	$77.5
Total	$1,430.5	($51.0)	$0.0	$1,379.6	$1,003.8	($22.1)	$0.0	$981.7

Monthly Marginal Loss Costs

Table 10-12 shows a monthly summary of marginal loss costs by type for 2011 and 2012.

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 (load energy payments less generation energy credits) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (load loss payments less generation loss credits) plus net explicit loss costs plus net inadvertent loss charges.

21 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.

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 10-13 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for 2009 through 2012.

Table 10-13 Marginal loss credits (Dollars (Millions)): 2009 through 2012[22]

	Loss Credit Accounting (Millions)			
	Total Energy Costs	Total Marginal Loss Costs	Net Residual Adjustments	Loss Credits
2009	($628.8)	$1,267.7	$0.8	$639.7
2010	($797.9)	$1,634.8	($0.5)	$836.4
2011	($793.7)	$1,379.6	$0.9	$586.8
2012	($593.0)	$981.7	($2.0)	$386.7

Congestion

Congestion Accounting

Transmission congestion occurs in the Day-Ahead and Real-Time Energy Market.[23] Total congestion costs are equal to the net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[24]

Load Congestion Payments and Generation Congestion Credits are calculated for both the Day-Ahead and Balancing Energy Markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.

- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and Day-Ahead Energy Market purchase transactions. Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.

- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs equal the product of the deviations between the real-time and day-ahead transacted MWs and the differences between the real- time CLMP at the transactions' sources and sinks.

- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy

22 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.

23 When the term *congestion charges* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

24 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[25]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[26]

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[27] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface

25 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

26 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs."

27 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion costs in PJM 2012 were $529.0 million, which was comprised of load congestion payments of $138.5 million, generation credits of -$444.0 million and explicit congestion of -$53.5 million (Table 10-15).

Total Congestion

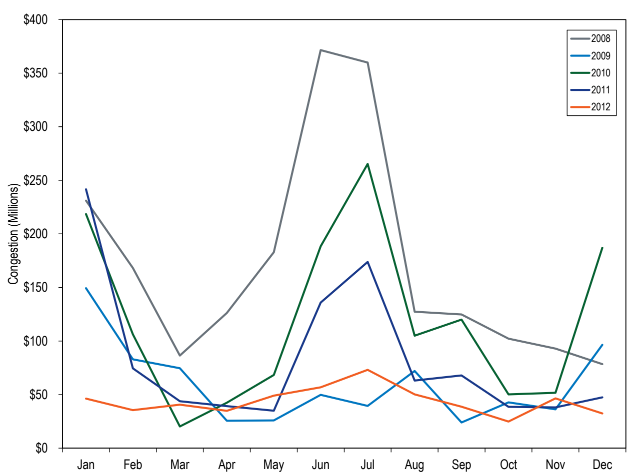
Table 10-14 shows total congestion for 2008 to 2012.[28]

Table 10-14 Total PJM congestion (Dollars (Millions)): 2008 to 2012

Congestion Costs (Millions)				
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,051.8	NA	$34,306.0	6.0%
2009	$719.0	(65.0%)	$26,550.0	2.7%
2010	$1,423.3	98.0%	$34,771.0	4.1%
2011	$999.0	(29.8%)	$35,887.0	2.8%
2012	$529.0	(47.0%)	$29,181.0	1.8%

Figure 10-1 shows PJM monthly congestion for 2008 through 2012.

Figure 10-1 PJM monthly congestion (Dollars (Millions)): 2008 to 2012



Total congestion costs in Table 10-15 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO.[29]

Table 10-16 shows the 2012 congestion costs by category. The 2012 PJM total congestion costs were comprised of $138.5 million in load congestion payments, -$444.0 million in generation congestion credits, and -$53.5 million in explicit congestion costs.

Table 10-15 Total PJM congestion costs by category (Dollars (Millions)): 2011 to 2012

Congestion Costs (Millions)					
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2011	$112.2	($1,009.9)	($123.1)	$0.0	$999.0
2012	$138.5	($444.0)	($53.5)	$0.0	$529.0

28 Congestion charges for 2010 reflect an updated calculation compared to the results in the *2010 State of the Market Report for PJM.*

29 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 March 13, 2012).

Table 10-16 Total PJM congestion costs by market category (Dollars (Millions)): 2011 to 2012

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2011	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$0.0	$999.0
2012	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$0.0	$529.0

Monthly Congestion

Table 10-17 shows that during 2012, monthly congestion costs ranged from $24.9 million to $73.1 million. Table 10-18 shows the congestion costs during 2011. Monthly congestion costs in 2012 were lower than in 2011.

Table 10-17 Monthly PJM congestion costs (Dollars (Millions)): 2012

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Jan	$4.0	($53.1)	$9.3	$66.3	$1.0	$5.7	($15.4)	($20.0)	$0.0	$46.3
Feb	$9.1	($38.3)	$7.4	$54.8	($3.7)	$2.7	($12.8)	($19.2)	$0.0	$35.5
Mar	$10.4	($38.5)	$10.9	$59.8	($1.6)	$3.7	($13.8)	($19.1)	$0.0	$40.7
Apr	$11.7	($43.7)	$16.5	$72.0	($3.2)	$5.2	($28.7)	($37.1)	$0.0	$34.9
May	$13.4	($37.2)	$16.7	$67.2	$0.5	($2.6)	($21.2)	($18.2)	$0.0	$49.1
Jun	$14.0	($50.9)	$4.7	$69.6	$5.4	$8.3	($9.8)	($12.7)	$0.0	$56.8
Jul	$13.9	($67.6)	$9.5	$91.0	$3.3	$7.3	($13.9)	($17.9)	$0.0	$73.1
Aug	$23.9	($30.0)	$6.9	$60.8	$5.9	$6.9	($9.6)	($10.6)	$0.0	$50.2
Sep	$12.8	($44.0)	$4.9	$61.8	($3.9)	$6.9	($12.3)	($23.1)	$0.0	$38.7
Oct	$2.6	($38.1)	$13.7	$54.4	($3.1)	$7.8	($18.7)	($29.6)	$0.0	$24.9
Nov	$10.3	($40.5)	$15.7	$66.4	$2.1	$9.3	($12.7)	($19.9)	$0.0	$46.5
Dec	$9.5	($30.5)	$15.8	$55.8	$0.3	$7.3	($16.4)	($23.4)	$0.0	$32.4
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$0.0	$529.0

Table 10-18 Monthly PJM congestion costs (Dollars (Millions)): 2011

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Jan	$27.0	($228.4)	$0.9	$256.4	$21.1	$15.6	($20.3)	($14.8)	$0.0	$241.6
Feb	$14.0	($77.5)	$1.0	$92.5	$5.6	$12.8	($10.9)	($18.0)	$0.0	$74.5
Mar	($2.5)	($58.8)	$2.2	$58.4	$0.2	$4.7	($10.0)	($14.6)	$0.0	$43.9
Apr	$5.0	($56.5)	$6.6	$68.0	$1.4	$6.4	($23.7)	($28.8)	$0.0	$39.2
May	$14.3	($41.5)	$8.6	$64.3	$3.0	$7.4	($24.9)	($29.3)	$0.0	$35.0
Jun	$1.8	($154.0)	$6.4	$162.3	$13.1	$22.4	($17.1)	($26.4)	$0.0	$135.9
Jul	$3.8	($184.1)	$6.5	$194.4	$21.2	$21.6	($20.2)	($20.6)	$0.0	$173.8
Aug	$4.7	($63.7)	$6.6	$75.0	($0.4)	$1.8	($9.7)	($11.9)	$0.0	$63.1
Sep	$0.0	($84.9)	$6.9	$91.9	$8.8	$21.2	($11.5)	($23.9)	$0.0	$67.9
Oct	($8.7)	($59.7)	$6.9	$58.0	$2.1	$6.2	($15.2)	($19.4)	$0.0	$38.6
Nov	($12.6)	($64.6)	$5.3	$57.3	($0.6)	$6.8	($11.8)	($19.2)	$0.0	$38.1
Dec	($10.6)	($68.1)	$9.0	$66.5	$0.5	$5.0	($14.6)	($19.1)	$0.0	$47.4
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$0.0	$999.0

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 2012, there were 249,572 day-ahead, congestion-event hours compared to 155,670 day-ahead, congestion-event hours in 2011. In 2012, there were 20,917 real-time, congestion-event hours compared to 22,513 real-time, congestion-event hours in 2011.

During 2012, for only 3.2 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During 2012, for 38.3 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 2012. With $68.5 million in total congestion costs, it accounted for 16.1 percent of the total PJM congestion costs in 2012. The top five constraints in terms of congestion costs together contributed $177.0 million, or 41.6 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South interface, Graceton – Raphael Road transmission line, Woodstock flowgate, Bedington - Black Oak interface and West interface.

Congestion by Facility Type and Voltage

In 2012, compared to 2011, day-ahead, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and MISO, transmission lines and transformers while congestion frequency on internal PJM interfaces decreased. Real-time, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and the MISO and transmission lines, while congestion frequency on interfaces and transformers decreased.

Day-ahead congestion costs increased on the reciprocally coordinated flowgates between PJM and MISO in 2012 compared to 2011 and decreased on PJM interfaces, transmission lines and transformers in 2012 compared to 2011. Balancing congestion costs increased on the reciprocally coordinated flowgates between PJM and MISO and transformers and decreased on PJM interfaces and transmission lines in 2012 compared to 2011.

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the 2012 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[30,31] For comparison, this information is presented in Table 10-20 for 2011.[32]

Table 10-21 and Table 10-22 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 10-21. In 2012, there were 249,572 congestion event hours in the Day-Ahead Market. Among those, only 8,098 (3.2 percent) were also constrained in the Real-Time Market. In 2011, among the 155,670 day-ahead congestion event hours, only 8,976 (5.8 percent) were binding in the Real-Time Market.[33]

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 10-22. In 2012, there were 20,917 congestion event hours in the Real-Time Market. Among these, 8,011 (38.3 percent) were also constrained in the Day-Ahead Market. In 2011, among the 22,513 real-time congestion event hours, only 8,885 (39.5 percent) were binding in the day-ahead.

30 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.

31 The term flowgate refers to MISO flowgates in this section.

32 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.

33 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 10-19 Congestion summary (By facility type): 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	($60.3)	($190.2)	$39.4	$169.3	($5.9)	$10.5	($81.5)	($97.9)	$71.4	29,500	7,772
Interface	$70.8	($68.8)	$2.9	$142.5	$14.6	$21.6	($3.6)	($10.6)	$131.9	7,005	737
Line	$78.0	($193.3)	$63.2	$334.6	($9.0)	$31.4	($82.8)	($123.2)	$211.3	144,670	10,151
Other	$9.7	($4.3)	$2.0	$16.0	($0.6)	$0.0	($0.9)	($1.6)	$14.4	8,007	433
Transformer	$31.1	($54.8)	$22.7	$108.5	$4.4	$3.8	($15.5)	($14.9)	$93.6	60,390	1,824
Unclassified	$6.2	($1.2)	$1.7	$9.1	($0.5)	$1.2	($1.2)	($2.8)	$6.3	NA	NA
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$529.0	249,572	20,917

Table 10-20 Congestion summary (By facility type): 2011

	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	($109.0)	($212.8)	$11.0	$114.8	$8.4	$22.9	($88.5)	($103.0)	$11.8	23,179	7,423
Interface	$64.0	($395.3)	($10.7)	$448.7	$37.7	$38.3	$7.1	$6.4	$455.1	9,013	1,803
Line	$45.6	($346.3)	$39.5	$431.3	$23.2	$51.2	($67.1)	($95.1)	$336.2	89,956	9,259
Other	($0.5)	($4.7)	$0.1	$4.3	$2.2	$4.6	($0.4)	($2.8)	$1.5	1,042	248
Transformer	$35.1	($181.2)	$21.5	$237.8	$3.3	$14.5	($39.7)	($50.9)	$186.9	32,480	3,780
Unclassified	$1.1	($1.5)	$5.4	$8.0	$1.2	$0.3	($1.4)	($0.5)	$7.5	NA	NA
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0	155,670	22,513

Table 10-21 Congestion Event Hours (Day Ahead against Real Time): Calendar years 2011 to 2012

	Congestion Event Hours					
	2012			2011		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	29,500	3,239	11.0%	23,179	2,917	12.6%
Interface	7,005	369	5.3%	9,013	1,144	12.7%
Line	144,670	3,496	2.4%	89,956	3,211	3.6%
Other	8,007	265	3.3%	1,042	67	6.4%
Transformer	60,390	729	1.2%	32,480	1,637	5.0%
Total	249,572	8,098	3.2%	155,670	8,976	5.8%

Table 10-22 Congestion Event Hours (Real Time against Day Ahead): 2011 to 2012

	Congestion Event Hours					
	2012			2011		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	7,772	3,320	42.7%	7,423	2,922	39.4%
Interface	737	395	53.6%	1,803	1,143	63.4%
Line	10,151	3,382	33.3%	9,259	3,150	34.0%
Other	433	229	52.9%	248	63	25.4%
Transformer	1,824	685	37.6%	3,780	1,607	42.5%
Total	20,917	8,011	38.3%	22,513	8,885	39.5%

Table 10-23 shows congestion costs by facility voltage class for 2012. In comparison to 2011 (shown in Table 10-24), congestion costs decreased across 765kV, 500kV, 345kV and 230kV in 2012.

Table 10-23 Congestion summary (By facility voltage): 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	($0.2)	($3.4)	$3.2	$6.5	$0.2	($0.1)	($0.1)	$0.1	$6.6	3,412	89
500	$75.3	($79.3)	$5.2	$159.9	$19.7	$25.8	($8.4)	($14.6)	$145.3	12,025	1,129
345	($41.6)	($135.1)	$23.7	$117.2	$1.6	$7.8	($35.7)	($41.9)	$75.3	34,050	3,623
230	$67.2	($72.4)	$19.8	$159.3	$4.8	$11.0	($38.7)	($44.9)	$114.5	35,443	4,052
161	($14.3)	($23.3)	$3.8	$12.7	($1.5)	$1.9	($10.2)	($13.6)	($0.9)	3,622	1,407
138	($9.1)	($202.1)	$69.7	$262.7	($9.0)	$15.5	($89.6)	($114.1)	$148.7	130,390	8,661
115	$24.1	($1.5)	$3.6	$29.2	($0.5)	$2.1	($1.4)	($4.0)	$25.2	18,614	901
69	$28.0	$5.9	$1.1	$23.1	($11.8)	$3.3	($0.1)	($15.3)	$7.9	10,531	1,053
34	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	1,470	2
12	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
Unclassified	$6.2	($1.2)	$1.7	$9.1	($0.5)	$1.2	($1.2)	($2.8)	$6.3	NA	NA
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$529.0	249,572	20,917

Table 10-24 Congestion summary (By facility voltage): 2011

	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	$0.8	($9.3)	$2.3	$12.4	$2.9	$2.1	($2.6)	($1.8)	$10.6	1,109	183
500	$100.0	($466.5)	($5.4)	$561.0	$42.4	$47.2	($11.1)	($15.9)	$545.1	17,936	3,691
345	($98.5)	($264.2)	$15.6	$181.2	$10.3	$26.3	($69.4)	($85.5)	$95.8	29,923	4,559
230	$1.7	($175.8)	$12.5	$190.1	$18.3	$21.4	($37.1)	($40.2)	$149.9	23,752	3,540
161	($13.6)	($22.0)	$6.3	$14.6	($2.5)	$6.0	($20.8)	($29.3)	($14.7)	1,760	1,152
138	$21.2	($173.7)	$26.1	$221.0	$4.4	$19.0	($46.1)	($60.7)	$160.3	60,087	7,691
115	$7.4	($27.8)	$4.2	$39.5	$1.1	$7.3	($1.5)	($7.7)	$31.8	12,193	1,109
69	$16.1	($1.1)	($0.1)	$17.1	($2.2)	$2.2	$0.1	($4.4)	$12.7	8,872	583
35	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	5
14	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
12	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	18	0
Unclassified	$1.1	($1.5)	$5.4	$8.0	$1.2	$0.3	($1.4)	($0.5)	$7.5	9,999	9,999
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0	155,670	22,513

Constraint Duration

Table 10-25 lists constraints in 2011 to 2012 that were most frequently in effect and Table 10-26 shows the constraints which experienced the largest change in congestion-event hours from 2011 to 2012.

Table 10-25 Top 25 constraints with frequent occurrence: 2011 to 2012

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2011	2012	Change	2011	2012	Change	2011	2012	Change	2011	2012	Change
1	Sporn	Transformer	972	18,619	17,647	0	0	0	11%	212%	201%	0%	0%	0%
2	Oak Grove - Galesburg	Flowgate	1,760	3,622	1,862	1,145	1,359	214	20%	41%	21%	13%	15%	2%
3	Linden - VFT	Line	2,616	3,847	1,231	0	0	0	30%	44%	14%	0%	0%	0%
4	Kammer	Transformer	1,289	3,440	2,151	69	19	(50)	15%	39%	24%	1%	0%	(1%)
5	Huntingdon - Huntingdon1	Line	558	3,421	2,863	0	0	0	6%	39%	33%	0%	0%	0%
6	Graceton - Raphael Road	Line	1,162	2,664	1,502	415	723	308	13%	30%	17%	5%	8%	3%
7	Monticello - East Winamac	Flowgate	823	2,734	1,911	241	578	337	9%	31%	22%	3%	7%	4%
8	Breed - Wheatland	Flowgate	0	2,821	2,821	215	428	213	0%	32%	32%	2%	5%	2%
9	Taylor - Grenshaw	Line	0	3,088	3,088	0	0	0	0%	35%	35%	0%	0%	0%
10	Bayway - Federal Square	Line	1,146	3,034	1,888	15	48	33	13%	35%	21%	0%	1%	0%
11	Big Sandy - Grangston	Line	740	3,066	2,326	0	0	0	8%	35%	26%	0%	0%	0%
12	AP South	Interface	4,120	2,586	(1,534)	1,013	351	(662)	47%	29%	(18%)	12%	4%	(8%)
13	Nelson - Cordova	Line	606	2,643	2,037	105	288	183	7%	30%	23%	1%	3%	2%
14	Crete - St Johns Tap	Flowgate	3,378	2,377	(1,001)	1,120	277	(843)	39%	27%	(12%)	13%	3%	(10%)
15	Devon - Skokie	Line	0	2,627	2,627	0	0	0	0%	30%	30%	0%	0%	0%
16	Bellefonte - Grangston	Line	50	2,603	2,553	0	0	0	1%	30%	29%	0%	0%	0%
17	Prairie State - W Mt. Vernon	Flowgate	234	1,483	1,249	149	1,011	862	3%	17%	14%	2%	12%	10%
18	Howard - Shelby	Line	554	2,460	1,906	0	0	0	6%	28%	22%	0%	0%	0%
19	Cumberland - Bush	Flowgate	1,612	2,053	441	215	316	101	18%	23%	5%	2%	4%	1%
20	Rantoul - Rantoul Jct	Flowgate	553	2,036	1,483	188	315	127	6%	23%	17%	2%	4%	1%
21	Danville - East Danville	Line	4,632	2,234	(2,398)	323	14	(309)	53%	25%	(27%)	4%	0%	(4%)
22	Rockwell - Crosby	Line	571	2,212	1,641	0	0	0	7%	25%	19%	0%	0%	0%
23	Conesville	Transformer	1,250	2,195	945	0	0	0	14%	25%	11%	0%	0%	0%
24	AEP - DOM	Interface	1,789	2,095	306	185	61	(124)	20%	24%	3%	2%	1%	(1%)
25	Diversey - Clybourn	Line	237	2,107	1,870	2	0	(2)	3%	24%	21%	0%	0%	(0%)

Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: 2011 to 2012

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2011	2012	Change	2011	2012	Change	2011	2012	Change	2011	2012	Change
1	Sporn	Transformer	972	18,619	17,647	0	0	0	11%	212%	201%	0%	0%	0%
2	South Mahwah - Waldwick	Line	5,269	210	(5,059)	494	0	(494)	60%	2%	(58%)	6%	0%	(6%)
3	Taylor - Grenshaw	Line	0	3,088	3,088	0	0	0	0%	35%	35%	0%	0%	0%
4	Belmont	Transformer	4,371	1,737	(2,634)	497	60	(437)	50%	20%	(30%)	6%	1%	(5%)
5	Breed - Wheatland	Flowgate	0	2,821	2,821	215	428	213	0%	32%	32%	2%	5%	2%
6	Huntingdon - Huntingdon1	Line	558	3,421	2,863	0	0	0	6%	39%	33%	0%	0%	0%
7	Danville - East Danville	Line	4,632	2,234	(2,398)	323	14	(309)	53%	25%	(27%)	4%	0%	(4%)
8	Michigan City - Laporte	Flowgate	2,935	873	(2,062)	632	40	(592)	34%	10%	(24%)	7%	0%	(7%)
9	Devon - Skokie	Line	0	2,627	2,627	0	0	0	0%	30%	30%	0%	0%	0%
10	Bellefonte - Grangston	Line	50	2,603	2,553	0	0	0	1%	30%	29%	0%	0%	0%
11	Electric Jct - Nelson	Line	2,943	636	(2,307)	158	5	(153)	34%	7%	(26%)	2%	0%	(2%)
12	Big Sandy - Grangston	Line	740	3,066	2,326	0	0	0	8%	35%	26%	0%	0%	0%
13	Fairview	Transformer	2,288	0	(2,288)	0	0	0	26%	0%	(26%)	0%	0%	0%
14	Monticello - East Winamac	Flowgate	823	2,734	1,911	241	578	337	9%	31%	22%	3%	7%	4%
15	Nelson - Cordova	Line	606	2,643	2,037	105	288	183	7%	30%	23%	1%	3%	2%
16	AP South	Interface	4,120	2,586	(1,534)	1,013	351	(662)	47%	29%	(18%)	12%	4%	(8%)
17	Cox's Corner - Marlton	Line	2,625	468	(2,157)	0	0	0	30%	5%	(25%)	0%	0%	0%
18	Prairie State - W Mt. Vernon	Flowgate	234	1,483	1,249	149	1,011	862	3%	17%	14%	2%	12%	10%
19	Kammer	Transformer	1,289	3,440	2,151	69	19	(50)	15%	39%	24%	1%	0%	(1%)
20	Pinehill - Stratford	Line	2,367	288	(2,079)	0	0	0	27%	3%	(24%)	0%	0%	0%
21	Oak Grove - Galesburg	Flowgate	1,760	3,622	1,862	1,145	1,359	214	20%	41%	21%	13%	15%	2%
22	Bunsonville - Eugene	Flowgate	2,444	236	(2,208)	11	148	137	28%	3%	(25%)	0%	2%	2%
23	Emilie - Falls	Line	2,938	902	(2,036)	11	1	(10)	34%	10%	(23%)	0%	0%	(0%)
24	Bayway - Federal Square	Line	1,146	3,034	1,888	15	48	33	13%	35%	21%	0%	1%	0%
25	Tanners Creek	Transformer	0	1,911	1,911	0	0	0	0%	22%	22%	0%	0%	0%

Constraint Costs

Table 10-27 and Table 10-28 present the top constraints affecting congestion costs by facility for 2012 through 2011.

Table 10-27 Top 25 constraints affecting PJM congestion costs (By facility): 2012

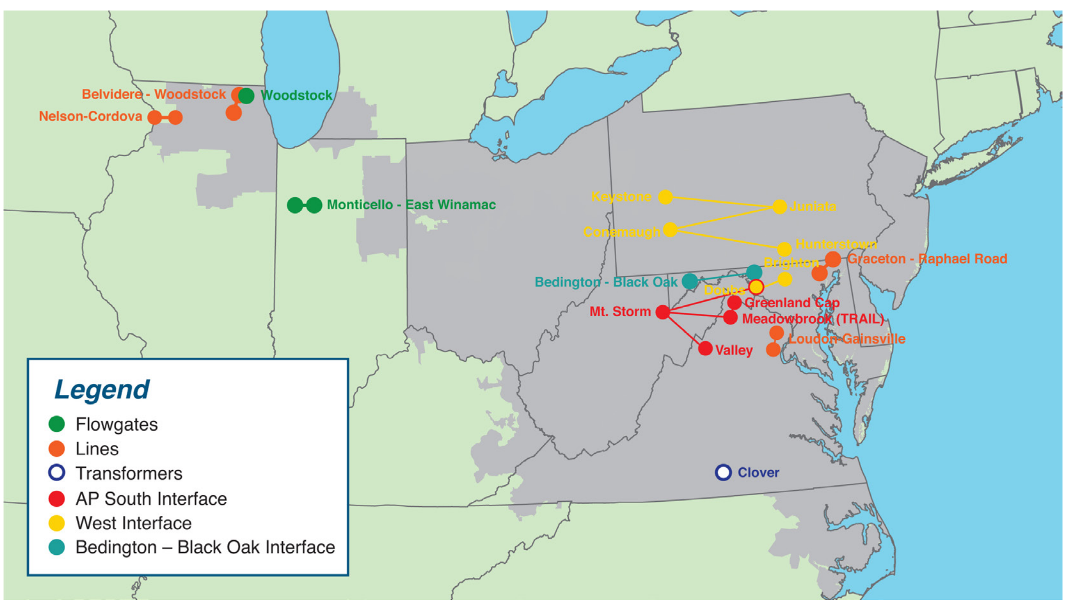
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2012
1	AP South	Interface	500	$48.3	($20.0)	$2.2	$70.5	$8.3	$7.6	($2.7)	($2.1)	$68.5	16.1%
2	Graceton - Raphael Road	Line	BGE	$26.5	($7.7)	($1.1)	$33.1	$1.0	($1.2)	($0.3)	$1.9	$35.0	8%
3	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	7%
4	West	Interface	500	$2.5	($24.7)	($0.5)	$26.7	$1.6	$4.0	$0.1	($2.3)	$24.4	6%
5	Bedington - Black Oak	Interface	500	$13.6	($6.0)	$0.4	$20.0	$1.0	$1.1	($0.7)	($0.8)	$19.1	4%
6	Clover	Transformer	Dominion	$9.4	($7.5)	$6.7	$23.6	$0.9	$0.8	($8.5)	($8.3)	$15.2	4%
7	Belvidere - Woodstock	Line	ComEd	($0.9)	($8.5)	$0.2	$7.7	($2.4)	$3.3	($16.3)	($22.0)	($14.3)	(3.4%)
8	Monticello - East Winamac	Flowgate	MISO	($0.2)	($19.6)	$11.5	$31.0	$0.4	$1.9	($15.5)	($17.0)	$14.0	3%
9	Nelson - Cordova	Line	ComEd	($19.3)	($34.3)	$6.9	$21.9	($0.9)	$1.7	($7.9)	($10.5)	$11.3	3%
10	Loudoun - Gainsville	Line	Dominion	$0.4	($11.0)	($1.2)	$10.3	$0.6	$0.9	$0.2	($0.1)	$10.2	2%
11	AEP - DOM	Interface	500	$8.3	($3.9)	$0.7	$12.9	$1.0	$4.2	($0.4)	($3.6)	$9.3	2%
12	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	2%
13	Rantoul - Rantoul Jct	Flowgate	MISO	($7.3)	($13.0)	$4.3	$10.0	($0.2)	($0.1)	($1.7)	($1.9)	$8.2	1.9%
14	Hunterstown	Transformer	Met-Ed	$3.4	($4.2)	$0.2	$7.9	$0.1	$0.0	($0.0)	$0.0	$7.9	2%
15	Crete - St Johns Tap	Flowgate	MISO	($5.6)	($19.2)	$0.1	$13.8	$0.3	$0.9	($5.7)	($6.3)	$7.5	2%
16	Pleasant Valley - Belvidere	Line	ComEd	($2.3)	($8.5)	$1.6	$7.8	$0.1	$0.1	($0.8)	($0.7)	$7.1	2%
17	Prairie State - W Mt. Vernon	Flowgate	MISO	($4.8)	($10.7)	$1.9	$7.7	($0.0)	($0.0)	($0.7)	($0.7)	$7.0	2%
18	Kammer	Transformer	AEP	($3.0)	($11.2)	($1.2)	$7.0	($0.2)	$0.1	$0.2	($0.0)	$7.0	2%
19	Sporn	Transformer	AEP	($0.1)	($0.6)	$6.0	$6.5	$0.0	$0.0	$0.0	$0.0	$6.5	1.5%
20	Harwood - Susquehanna	Line	PPL	$0.7	($5.4)	$0.3	$6.4	$0.1	$0.1	$0.1	$0.1	$6.5	2%
21	Unclassified	Unclassified	Unclassified	$6.2	($1.2)	$1.7	$9.1	($0.5)	$1.2	($1.2)	($2.8)	$6.3	1%
22	Leonia - New Milford	Line	PSEG	$1.5	$1.8	$2.7	$2.4	($0.4)	$0.4	($7.2)	($7.9)	($5.6)	(1%)
23	Breed - Wheatland	Flowgate	MISO	($2.8)	($17.9)	$0.5	$15.6	$0.4	$0.3	($10.1)	($10.1)	$5.5	1%
24	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.2	($0.1)	$0.0	$5.1	1%
25	Belmont	Transformer	AP	$0.6	($5.5)	$0.6	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	1.2%

Table 10-28 Top 25 constraints affecting PJM congestion costs (By facility): 2011

				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	2011
1	AP South	Interface	500	$96.1	($140.1)	($0.1)	$236.1	$18.7	$16.0	$0.0	$2.8	$238.9	27%
2	5004/5005 Interface	Interface	500	($25.2)	($101.5)	($4.6)	$71.7	$16.1	$19.3	$7.6	$4.3	$76.1	9%
3	West	Interface	500	($19.3)	($83.4)	($5.0)	$59.1	$0.2	$0.1	$0.1	$0.3	$59.3	7%
4	Belmont	Transformer	AP	$7.7	($49.9)	($2.2)	$55.5	($3.5)	($3.2)	($1.6)	($1.8)	$53.7	6%
5	AEP - DOM	Interface	500	$14.6	($21.5)	$2.1	$38.2	$2.0	$1.5	($0.4)	$0.1	$38.3	4%
6	Electric Jct - Nelson	Line	ComEd	($10.8)	($44.4)	$7.7	$41.3	$0.4	$3.7	($7.7)	($11.0)	$30.3	3%
7	Bedington - Black Oak	Interface	500	$10.9	($14.6)	($2.0)	$23.5	$0.2	$0.1	$0.0	$0.1	$23.7	3%
8	Crete - St Johns Tap	Flowgate	MISO	($32.9)	($66.4)	($5.3)	$28.2	$6.3	$6.7	($4.5)	($4.9)	$23.3	3%
9	Clover	Transformer	Dominion	$0.4	($21.4)	$4.6	$26.4	$2.8	$3.4	($7.8)	($8.5)	$17.9	2%
10	East	Interface	500	($11.5)	($31.5)	($1.2)	$18.7	$0.2	$1.3	$0.1	($1.0)	$17.8	2%
11	Dickerson - Quince Orchard	Line	Pepco	($9.4)	($28.8)	($1.7)	$17.7	$4.6	$7.4	$2.7	($0.2)	$17.5	2%
12	Oak Grove - Galesburg	Flowgate	MISO	($13.6)	($22.0)	$6.3	$14.6	($2.5)	$6.0	($20.8)	($29.3)	($14.7)	(2%)
13	Susquehanna	Transformer	PPL	($2.9)	($17.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	2%
14	Graceton - Raphael Road	Line	BGE	$10.9	($1.1)	($0.8)	$11.2	$0.7	($1.1)	$0.5	$2.4	$13.5	2%
15	Wylie Ridge	Transformer	AP	$15.3	$3.6	$1.8	$13.6	$2.2	$1.2	($2.5)	($1.5)	$12.1	1%
16	East Frankfort - Crete	Line	ComEd	($10.0)	($23.7)	($1.3)	$12.4	$0.6	$0.6	($0.6)	($0.6)	$11.8	1%
17	Brues - West Bellaire	Line	AEP	$19.8	$4.5	$0.7	$16.1	($2.1)	$1.8	($1.5)	($5.4)	$10.7	1%
18	Breed - Wheatland	Line	AEP	($4.8)	($13.2)	$2.0	$10.5	$0.0	($0.0)	($0.1)	($0.0)	$10.4	1%
19	Waldwick	Transformer	PSEG	($0.5)	($2.3)	$2.1	$3.8	$0.1	$1.3	($12.5)	($13.8)	($9.9)	(1%)
20	Plymouth Meeting - Whitpain	Line	PECO	($0.9)	($10.8)	($0.0)	$9.9	$0.2	$0.2	($0.1)	($0.2)	$9.7	1%
21	Cloverdale	Transformer	AEP	$0.5	($7.6)	$1.6	$9.7	$0.7	$0.6	($0.1)	($0.0)	$9.7	1%
22	Bunsonville - Eugene	Flowgate	MISO	($11.5)	($19.0)	$2.1	$9.6	$0.0	($0.0)	($0.0)	($0.0)	$9.6	1%
23	Unclassified	Unclassified	Unclassified	$1.1	($1.5)	$5.4	$8.0	$1.2	$0.3	($1.4)	($0.5)	$7.5	1%
24	Pleasant Valley - Belvidere	Line	ComEd	($6.6)	($17.6)	$1.7	$12.7	($0.6)	$2.1	($3.0)	($5.7)	$7.0	1%
25	Cloverdale - Lexington	Line	500	$4.9	($2.9)	$1.3	$9.1	$3.3	$2.1	($3.8)	($2.7)	$6.4	1%

Figure 10-2 shows the locations of the top 10 constraints affecting PJM congestion costs in 2012.

Figure 10-2 Location of the top 10 constraints affecting PJM congestion costs: 2012[34]



34 The term flowgate refers to MISO reciprocal coordinated 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.[35] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[36] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 10-29 and Table 10-30 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2012 and 2011 respectively, 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 2012, the Woodstock flowgate made the most significant contribution to positive congestion while the Rising flowgate made the most significant contribution to negative congestion.

Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 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)	($19.6)	$11.5	$31.0	$0.4	$1.9	($15.5)	($17.0)	$14.0	2,734	578
3	Rantoul - Rantoul Jct	($7.3)	($13.0)	$4.3	$10.0	($0.2)	($0.1)	($1.7)	($1.9)	$8.2	2,036	315
4	Crete - St Johns Tap	($5.6)	($19.2)	$0.1	$13.8	$0.3	$0.9	($5.7)	($6.3)	$7.5	2,377	277
5	Prairie State - W Mt. Vernon	($4.8)	($10.7)	$1.9	$7.7	($0.0)	($0.0)	($0.7)	($0.7)	$7.0	1,483	1,011
6	Breed - Wheatland	($2.8)	($17.9)	$0.5	$15.6	$0.4	$0.3	($10.1)	($10.1)	$5.5	2,821	428
7	Rising	($3.1)	($3.2)	$2.3	$2.4	($1.2)	$0.8	($5.4)	($7.4)	($5.0)	408	363
8	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	$0.1	$0.4	($4.0)	($4.3)	($4.3)	0	331
9	Benton Harbor - Palisades	($0.6)	($5.5)	($0.8)	$4.1	$0.1	$0.3	($0.2)	($0.4)	$3.8	840	71
10	Miami Fort - Hebron	($1.8)	($5.7)	($0.2)	$3.7	($0.1)	($0.0)	$0.1	$0.0	$3.7	1,053	76
11	Palisades - Roosevelt	($0.9)	($5.6)	($0.6)	$4.1	$0.1	$0.3	($0.2)	($0.4)	$3.7	855	209
12	Cumberland - Bush	($1.2)	($5.5)	$6.2	$10.5	$0.4	$1.2	($11.1)	($11.8)	($1.3)	2,053	316
13	Brokaw	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($1.1)	($1.2)	($1.2)	0	81
14	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.2	($0.2)	($1.1)	($1.1)	0	36
15	Edwards - Kewanee	($0.2)	($0.9)	$0.5	$1.2	$0.0	($0.1)	($0.3)	($0.2)	$1.0	314	68
16	Michigan City - Maple	($1.0)	($0.7)	$0.5	$0.2	($0.4)	($0.1)	($0.8)	($1.1)	($0.9)	73	51
17	Beaver Channel - Albany	($6.0)	($17.0)	($0.1)	$11.0	($4.8)	($0.4)	($5.7)	($10.2)	$0.8	1,256	460
18	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.8)	($0.8)	($0.8)	0	20
19	Dunes Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	180	23
20	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.6)	($0.7)	($0.7)	0	296

35 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> (Accessed March 13, 2013).

36 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> (Accessed March 13, 2013).

Table 10-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2011

		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	Crete - St Johns Tap	($32.9)	($66.4)	($5.3)	$28.2	$6.3	$6.7	($4.5)	($4.9)	$23.3	3,378	1,120
2	Oak Grove - Galesburg	($13.6)	($22.0)	$6.3	$14.6	($2.5)	$6.0	($20.8)	($29.3)	($14.7)	1,760	1,145
3	Bunsonville - Eugene	($11.5)	($19.0)	$2.1	$9.6	$0.0	($0.0)	($0.0)	($0.0)	$9.6	2,444	11
4	Pleasant Prairie - Zion	($1.1)	($1.6)	$0.7	$1.2	($0.1)	($0.5)	($7.9)	($7.5)	($6.3)	336	210
5	Lakeview - Pleasant Prairie	($0.1)	($0.2)	$0.2	$0.3	($0.3)	($0.1)	($5.7)	($5.8)	($5.6)	24	302
6	Burnham - Munster	($10.9)	($19.0)	($3.0)	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	1,152	0
7	Stillwell	($0.0)	($0.4)	($0.1)	$0.3	($0.3)	$1.3	($3.6)	($5.2)	($4.9)	93	88
8	Michigan City - Laporte	($10.4)	($16.4)	$3.0	$9.0	($1.7)	($1.3)	($3.8)	($4.2)	$4.8	2,935	632
9	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.4	$0.3	($4.4)	($4.2)	($4.2)	0	215
10	Cook - Palisades	($1.3)	($5.2)	$0.3	$4.1	$0.0	$0.0	($0.2)	($0.2)	$3.9	481	9
11	Rantoul - Rantoul Jct	($3.2)	($5.5)	$0.6	$3.0	$0.1	$0.0	($0.5)	($0.4)	$2.6	553	188
12	Benton Harbor - Palisades	($0.2)	($1.0)	$0.2	$1.0	$0.8	$1.2	($2.8)	($3.2)	($2.2)	67	132
13	St John - Liberty Park	($1.8)	($6.0)	$0.6	$4.8	$0.6	$1.0	($2.2)	($2.6)	$2.2	334	161
14	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.2	$0.5	($1.8)	($2.1)	($2.1)	0	56
15	Temporary Monticello - E Wiinamac	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.5	($1.2)	($1.7)	($1.7)	0	69
16	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($1.7)	($1.6)	($1.6)	0	107
17	Cumberland - Bush	($1.0)	($5.8)	$2.1	$6.9	$0.2	$0.9	($4.6)	($5.3)	$1.6	1,612	215
18	Rising	($5.2)	($8.1)	($0.1)	$2.8	$0.0	$1.1	($3.3)	($4.4)	($1.6)	947	175
19	Green Acres - St John	$0.0	$0.0	$0.0	$0.0	$0.6	$1.4	($0.7)	($1.5)	($1.5)	0	147
20	Rantoul Jct - Sidney	($1.0)	($2.0)	$0.1	$1.1	$0.5	$0.0	($0.2)	$0.3	$1.3	62	113

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-31 and Table 10-32 show the 500 kV constraints impacting congestion costs in PJM for 2012 and 2011 respectively. 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 10-31 Regional constraints summary (By facility): 2012

				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	$48.3	($20.0)	$2.2	$70.5	$8.3	$7.6	($2.7)	($2.1)	$68.5	2,586	351
2	West	Interface	500	$2.5	($24.7)	($0.5)	$26.7	$1.6	$4.0	$0.1	($2.3)	$24.4	841	130
3	Bedington - Black Oak	Interface	500	$13.6	($6.0)	$0.4	$20.0	$1.0	$1.1	($0.7)	($0.8)	$19.1	780	54
4	AEP - DOM	Interface	500	$8.3	($3.9)	$0.7	$12.9	$1.0	$4.2	($0.4)	($3.6)	$9.3	2,095	61
5	East	Interface	500	($2.6)	($8.1)	($0.6)	$4.8	$0.1	$0.5	($0.1)	($0.5)	$4.4	209	5
6	5004/5005 Interface	Interface	500	$0.2	($4.1)	$0.5	$4.8	$2.5	$3.5	$0.3	($0.6)	$4.2	191	128
7	Doubs - Mount Storm	Line	500	$1.3	($1.1)	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	80	0
8	Conemaugh - Hunterstown	Line	500	$0.4	($1.3)	$0.1	$1.7	$0.1	$2.0	($1.9)	($3.9)	($2.1)	38	117
9	Central	Interface	500	($0.9)	($1.6)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	214	2
10	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.8)	($0.8)	($0.7)	7	61
11	Nagel	Line	500	$0.3	($0.0)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	128	0
12	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	12	19
13	Mount Storm - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2
14	Branchburg - Elroy	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0
15	Burches Hill - Chalk Point	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Table 10-32 Regional constraints summary (By facility): 2011

				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	$96.1	($140.1)	($0.1)	$236.1	$18.7	$16.0	$0.0	$2.8	$238.9	4,120	1,013
2	5004/5005 Interface	Interface	500	($25.2)	($101.5)	($4.6)	$71.7	$16.1	$19.3	$7.6	$4.3	$76.1	905	470
3	West	Interface	500	($19.3)	($83.4)	($5.0)	$59.1	$0.2	$0.1	$0.1	$0.3	$59.3	879	20
4	AEP - DOM	Interface	500	$14.6	($21.5)	$2.1	$38.2	$2.0	$1.5	($0.4)	$0.1	$38.3	1,789	185
5	Bedington - Black Oak	Interface	500	$10.9	($14.6)	($2.0)	$23.5	$0.2	$0.1	$0.0	$0.1	$23.7	679	7
6	East	Interface	500	($11.5)	($31.5)	($1.2)	$18.7	$0.2	$1.3	$0.1	($1.0)	$17.8	523	22
7	Cloverdale - Lexington	Line	500	$4.9	($2.9)	$1.3	$9.1	$3.3	$2.1	($3.8)	($2.7)	$6.4	602	427
8	Central	Interface	500	($1.5)	($2.8)	($0.0)	$1.3	($0.1)	($0.1)	($0.1)	($0.1)	$1.2	118	8
9	Mount Storm - Pruntytown	Line	500	$0.1	($0.2)	$0.0	$0.3	$0.2	$0.0	($0.1)	$0.0	$0.3	29	38
10	Doubs - Mount Storm	Line	500	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.3	9	4
11	Harrison - Pruntytown	Line	500	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
12	Kammer	Transformer	500	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	13	0
13	Dominion East	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.3	$0.1	($0.2)	$0.0	$0.0	0	38
14	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	9

Congestion Costs by Physical and Financial Participants

In order to evaluate the ownership of virtual bids, the MMU categorized 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. In 2012, financial companies as a group were net recipients of congestion credits, whereas physical companies were net payers of congestion charges.[37] In 2012, financial companies received $83.1 million, a decrease of $91.6 million or 52.4 percent compared to 2011. In 2012, physical companies paid $612.1 million in congestion charges, a decrease of $561.5 million or 47.8 percent compared to 2011.

Table 10-33 Congestion cost by the type of the participant: Calendar year 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	($0.2)	$11.1	$90.1	$78.8	($25.2)	($1.3)	($137.9)	($161.9)	$0.0	($83.1)
Physical	$135.8	($523.6)	$41.8	$701.1	$28.3	$69.8	($47.5)	($89.0)	$0.0	$612.1
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$0.0	$529.0

Table 10-34 Congestion cost by the type of the participant: Calendar year 2011

	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	($22.2)	$14.4	$69.5	$32.9	($26.8)	$9.1	($171.7)	($207.5)	$0.0	($174.7)
Physical	$58.5	($1,156.2)	($2.6)	$1,212.1	$102.7	$122.8	($18.4)	($38.5)	$0.0	$1,173.6
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$0.0	$999.0

37 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change.

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** At December 31, 2012, 76,387 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for approximately 21,359 MW of nameplate capacity, 28.0 percent of the MW in the queues, and combined-cycle projects account for 42,724 MW, 55.8 percent of the MW in the queues.
- **Generation Retirements.** A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through January 1, 2013, and it is expected that a total of 21,524.9 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through January 1, 2013, account for 8,453.2 MW. Units planning to retire in 2013 account for 237.4 MW, or 1.1 percent of planned retirements during this period. Overall, 3,951.1 MW, or 18.4 percent of all retirements from 2011 through 2019, are expected in the AEP 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 EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. 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.[1] 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 7,584.2 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. The total planned costs for all of these projects are approximately 1.7 billion dollars.

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.[2] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

1 OATT Parts IV & VI.

2 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).

- **Competitive Grid Development.** In Order No. 1000, the FERC requires that each public utility transmission provider (including PJM) remove from its FERC approved tariff and agreements, as necessary and subject to certain limitations, a federal right of first refusal (ROFR) for certain new transmission projects.[3,4] A key limitation is the ability to retain ROFR for upgrades to the existing transmission infrastructure.

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 1000, there is not yet a robust mechanism to permit competition between transmission developers to build transmission projects. 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.

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. At December 31, 2012, 76,387 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 11-1).[5] Overall, 2,669 MW of nameplate capacity were added in PJM in 2012 (excluding the integration of the DEOK zone).

Table 11-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2012[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

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 Y will be active through January 31, 2013.

Capacity in generation request queues for the seven year period beginning in 2012 and ending in 2018 decreased by 14,338 MW from 90,725 MW in 2011 to 76,387 MW in 2012, or 15.8 percent (Table 11-2).[7] Queued capacity scheduled for service in 2012 decreased from 27,184 MW to 12,301 MW, or 54.7 percent, though only 2,669 MW

3 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011).

4 *Id.* at PP 313–322.

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.

6 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

7 See the *2011 State of the Market Report for PJM*: Volume II, Section 11, pp. 286-288, for the queues in 2011.

went into service in 2012. Queued capacity scheduled for service in 2013 decreased from 13,051 MW to 9,819 MW, or 24.8 percent. The 76,387 MW include generation with scheduled in-service dates in 2012 and units still active in the queue with in-service dates scheduled before 2012, listed at nameplate capacity, although these units are not yet in service.

Table 11-2 Queue comparison (MW): December 31, 2012 vs. December 31, 2011

	MW in the Queue 2011	MW in the Queue 2012	Year-to-Year Change (MW)	Year-to-Year Change
2012	27,184	12,301	(14,883)	(54.7%)
2013	13,051	9,819	(3,232)	(24.8%)
2014	17,036	8,086	(8,950)	(52.5%)
2015	19,251	22,295	3,044	15.8%
2016	9,288	11,788	2,500	26.9%
2017	1,720	8,932	7,212	419.3%
2018	3,194	3,165	(29)	(0.9%)
Total	90,725	76,387	(14,338)	(15.8%)

Table 11-3 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.[8]

Table 11-3 Capacity in PJM queues (MW): At December 31, 2012[9,10]

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	525	17,409	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	80	2,345	2,643
L Expired 31-Jan-04	0	257	0	4,034	4,290
M Expired 31-Jul-04	0	505	422	3,556	4,482
N Expired 31-Jan-05	0	2,399	38	8,090	10,527
O Expired 31-Jul-05	10	1,491	1,025	5,066	7,592
P Expired 31-Jan-06	413	2,915	455	4,908	8,690
Q Expired 31-Jul-06	120	2,038	2,914	9,462	14,534
R Expired 31-Jan-07	1,426	1,216	778	19,334	22,755
S Expired 31-Jul-07	1,778	3,243	652	11,469	17,142
T Expired 31-Jan-08	4,140	1,259	631	21,516	27,546
U Expired 31-Jan-09	3,532	666	132	29,026	33,357
V Expired 31-Jan-10	5,626	259	1,626	9,494	17,005
W Expired 31-Jan-11	8,430	301	1,741	13,785	24,256
X Expired 31-Jan-12	17,882	80	2,028	10,396	30,386
Y Expires 31-Jan-13	19,852	0	132	947	20,931
Total	63,208	33,785	13,179	237,903	348,075

Data presented in Table 11-4 show that through 2012, 37.7 percent of total in-service capacity from all the queues was from Queues A and B and an additional 6.4

8 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.

9 The *2012 State of the Market Report for PJM* contains all projects in the queue including reratings of existing generating units and energy only resources.

10 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

percent was from Queues C, D and E.[11] As of December 31, 2012, 31.8 percent of the capacity in Queues A and B has been placed in service, and 9.7 percent of all queued capacity has been placed in service.

The data presented in Table 11-4 show that for successful projects there is an average time of 831 days between entering a queue and the in-service date, an increase of 29 days since 2011. The data also show that for withdrawn projects, there is an average time of 543 days between entering a queue and completion or exiting. For each status, there is substantial variability around the average results.

Table 11-4 Average project queue times (days): At December 31, 2012

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	882	634	0	2,801
In-Service	831	710	0	3,964
Suspended	2,155	922	704	3,849
Under Construction	1,412	785	0	5,083
Withdrawn	543	556	0	3,186

Table 11-5 shows active queued capacity that was planned to be in service by January 1, 2013. This indicates there is a substantial amount of queued capacity, 7,584.2 MW, that should already be in service based on the original queue date but that is not yet even under construction. The MMU recommends that a review process be created to ensure that projects are removed from the queue, if they are no longer viable and no longer planning to complete the project.

Table 11-5 Active capacity queued to be in service prior to January 1, 2013

	MW
2007	87.0
2008	347.0
2009	296.4
2010	2,160.5
2011	3,639.2
2012	1,054.1
Total	7,584.2

Distribution of Units in the Queues

A more detailed examination of the queue data permits some additional conclusions. 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. At December 31, 2012, 76,387 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for 21,359 MW of nameplate capacity or 28.0 percent of the capacity in the queues and combined-cycle projects account for 42,724 MW of capacity or 55.9 percent of the capacity in the queues.[12] On December 31, 2012, there were 42,724 MW of capacity from combined cycle units in the queue, compared to 34,788 MW in 2011, an increase of 22.8 percent. At December 31, 2012, there was queued combined cycle capacity in nearly every zone in PJM, and after accounting for the derating of wind and solar resources, combined cycle capacity comprises 75.9 percent of the MW in the queue able to offer into RPM auctions.

Table 11-6 shows the projects under construction or active as of December 31, 2012, by unit type and control zone. Most of the steam projects (99.4 percent of the MW) and most of the wind projects (93.8 percent of the MW) are outside the Eastern MAAC (EMAAC)[13] and Southwestern MAAC (SWMAAC)[14] locational deliverability areas (LDAs).[15] Of the total capacity additions, only 15,323 MW, or 20.1 percent, are projected to be in EMAAC, while 4,225 MW or 5.5 percent are projected to be constructed in SWMAAC. Of total capacity additions, 29,272 MW, or 38.3 percent of capacity, is being added inside MAAC zones. Overall, 74.4 percent of capacity is being added outside EMAAC and SWMAAC, and 61.6 percent of capacity is being added outside MAAC zones, not accounting for the planned integration of the EKPC zone in 2013. Wind projects account for 2,933 MW of capacity in MAAC LDAs, or 10.0 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 1,319 MW of capacity, or 8.6 percent.

11 The data for Queue Y include projects through September 30, 2012.

12 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. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 21,359 MW of wind resources and 2,447 MW of solar resources, the 76,387 MW currently active in the queue would be reduced to 56,288 MW.

13 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.

14 SWMAAC consists of the BGE and Pepco Control Zones.

15 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

Table 11-6 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2012

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	3,495	63	9	0	0	516	0	0	1,069	5,152
AEP	6,124	0	13	70	0	104	2,069	84	10,628	19,091
AP	2,044	0	33	75	0	143	918	0	526	3,739
ATSI	3,851	40	10	0	30	22	135	0	849	4,937
BGE	678	256	4	0	0	22	0	0	0	960
ComEd	1,440	444	102	23	607	65	600	42	4,959	8,282
DAY	0	0	2	112	0	23	12	12	845	1,006
DEOK	20	0	0	0	0	0	0	0	0	20
DLCO	245	0	0	0	91	0	0	0	0	336
Dominion	6,501	535	11	0	1,594	80	364	0	619	9,703
DPL	1,223	2	0	0	0	270	22	0	230	1,746
JCPL	2,550	0	30	0	0	883	0	0	0	3,463
Met-Ed	1,818	0	18	0	58	3	0	0	0	1,897
PECO	114	7	4	0	470	10	0	5	0	609
PENELEC	879	43	231	0	0	32	106	0	1,194	2,485
Pepco	3,245	0	20	0	0	0	0	0	0	3,265
PPL	4,716	0	10	3	100	74	0	20	420	5,342
PSEG	3,783	290	9	0	50	200	0	2	20	4,353
Total	42,724	1,680	505	283	3,000	2,447	4,225	164	21,359	76,387

Table 11-7 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2012[16]

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	11,164	362	52	0	520	1,879	22	7	1,319	15,323
SWMAAC	3,923	256	24	0	0	22	0	0	0	4,225
WMAAC	7,413	43	258	3	158	109	106	20	1,614	9,724
Non-MAAC	20,225	1,019	171	280	2,322	437	4,098	138	18,426	47,115
Total	42,724	1,680	505	283	3,000	2,447	4,225	164	21,359	76,387

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units are replaced by units burning natural gas. (Table 11-7)

Table 11-8 shows existing generation by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity is distributed across control zones.

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 11-6) 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.

16 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 11-8 Existing PJM capacity: At January 1, 2013[17] (By zone and unit type (MW))

	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	701	21	0	0	0	40	1,087	0	8	2,020
AEP	4,900	3,682	60	0	1,072	2,071	0	21,512	0	1,753	35,050
AP	1,129	1,215	48	0	80	0	36	7,358	27	999	10,892
ATSI	685	1,661	71	0	0	2,134	0	6,540	0	0	11,091
BGE	0	835	11	0	0	1,716	0	3,007	0	0	5,569
ComEd	1,763	7,257	94	0	0	10,438	0	5,417	5	2,454	27,427
DAY	0	1,369	48	0	0	0	1	4,368	0	0	5,785
DEOK	0	842	0	0	0	0	0	2,646	0	0	3,488
DLCO	244	15	0	0	6	1,777	0	784	0	0	2,826
Dominion	4,030	3,762	174	0	3,589	3,581	3	8,320	0	0	23,458
DPL	1,125	1,820	96	30	0	0	4	1,800	0	0	4,876
External	974	990	0	0	66	439	0	5,728	0	185	8,382
JCPL	1,693	1,233	27	0	400	615	42	15	0	0	4,024
Met-Ed	2,051	408	41	0	20	805	0	844	0	0	4,168
PECO	3,209	836	3	0	1,642	4,547	3	979	1	0	11,220
PENELEC	0	344	46	0	513	0	0	6,831	0	931	8,663
Pepco	230	1,092	12	0	0	0	0	3,649	0	0	4,983
PPL	1,804	617	49	0	582	2,520	15	5,537	0	220	11,342
PSEG	3,091	2,838	12	0	5	3,493	105	2,052	0	0	11,597
Total	27,091	31,515	811	30	7,974	34,135	249	88,473	33	6,549	196,860

Table 11-9 shows the age of PJM generators by unit type.

Table 11-9 PJM capacity (MW) by age: at January 1, 2013

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	18,993	9,253	459	30	11	0	249	2,482	33	6,515	38,025
11 to 20	6,062	13,070	106	0	48	0	0	3,261	0	34	22,582
21 to 30	1,594	1,663	56	0	3,448	15,409	0	8,504	0	0	30,674
31 to 40	244	3,108	43	0	105	16,361	0	28,696	0	0	48,557
41 to 50	198	4,420	132	0	2,915	2,365	0	29,339	0	0	39,369
51 to 60	0	0	15	0	379	0	0	13,516	0	0	13,910
61 to 70	0	0	0	0	0	0	0	2,526	0	0	2,526
71 to 80	0	0	0	0	280	0	0	95	0	0	375
81 to 90	0	0	0	0	549	0	0	54	0	0	603
91 to 100	0	0	0	0	155	0	0	0	0	0	155
101 and over	0	0	0	0	84	0	0	0	0	0	84
Total	27,091	31,515	811	30	7,974	34,135	249	88,473	33	6,549	196,860

Table 11-10 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 2018. 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 88.7 percent of all new capacity in EMAAC when the derating of wind and solar capacity is reflected.

In 2012, a planned addition of 1,640 MW of nuclear capacity to Calvert Cliffs in SWMAAC was withdrawn from the queue. Without the planned nuclear capability in SWMAAC, new gas-fired capability represents 98.9 percent of all new capability in the SWMAAC. In 2018, this would mean that CC and CT generators would comprise 55.0 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.[18] In these zones, 87.8 percent of all generation 40 years or older is steam (primarily coal). With the retirement of these units in 2018, wind farms would comprise 16.8 percent of total MW ICAP in Non-MAAC zones, if all queued MW are built.

17 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

18 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion Control Zones.

Table 11-10 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[19]

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 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Combined Cycle	198	2.4%	9,282	27.5%	11,164	20,248	48.7%
	Combustion Turbine	2,229	27.5%	7,428	22.0%	362	5,561	13.4%
	Diesel	48	0.6%	159	0.5%	52	163	0.4%
	Fuel Cell	0	0.0%	30	1.6%	0	30	1.8%
	Hydroelectric	2,042	25.2%	2,047	6.1%	0	620	1.5%
	Nuclear	615	7.6%	8,654	25.7%	520	8,560	20.6%
	Solar	0	0.0%	194	0.6%	1,879	2,073	5.0%
	Steam	2,981	36.7%	5,933	17.6%	22	2,974	7.2%
	Storage	0	0.0%	1	0.0%	7	8	0.0%
	Wind	0	0.0%	8	0.0%	1,319	1,327	3.2%
	EMAAC Total	8,112	100.0%	33,736	100.0%	15,323	41,562	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	2.2%	3,923	4,153	39.4%
	Combustion Turbine	542	12.8%	1,927	18.3%	256	1,640	15.6%
	Diesel	0	0.0%	23	0.2%	24	47	0.4%
	Nuclear	0	0.0%	1,716	16.3%	0	1,716	16.3%
	Solar	0	0.0%	0	0.0%	22	22	0.2%
	Steam	3,702	87.2%	6,656	63.1%	0	2,954	28.0%
	SWMAAC Total	4,244	100.0%	10,552	100.0%	4,225	10,533	100.0%
WMAAC	Combined Cycle	0	0.0%	3,855	15.9%	7,413	11,268	78.7%
	Combustion Turbine	558	6.1%	1,368	5.7%	43	854	6.0%
	Diesel	46	0.5%	136	0.6%	259	348	2.4%
	Hydroelectric	887	9.7%	1,114	4.6%	3	1,117	7.8%
	Nuclear	0	0.0%	3,325	13.8%	158	3,483	24.3%
	Solar	0	0.0%	15	0.1%	109	124	0.9%
	Steam	7,702	83.8%	13,211	54.7%	106	5,616	39.2%
	Storage	0	0.0%	0	0.0%	20	20	0.1%
	Wind	0	0.0%	1,151	4.8%	1,614	2,764	19.3%
	WMAAC Total	9,193	100.0%	24,174	100.0%	9,724	14,325	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,724	10.7%	20,225	33,949	24.0%
	Combustion Turbine	1,092	3.1%	20,792	16.2%	1,019	20,719	14.6%
	Diesel	53	0.1%	494	0.4%	171	612	0.4%
	Hydroelectric	1,433	4.0%	4,814	3.7%	280	5,093	3.6%
	Nuclear	1,751	4.9%	20,440	15.9%	2,322	21,011	14.9%
	Solar	0	0.0%	40	0.0%	437	477	0.3%
	Steam	31,146	87.8%	62,672	48.8%	4,098	35,624	25.2%
	Storage	0	0.0%	32	0.0%	138	170	0.1%
	Wind	0	0.0%	5,391	4.2%	18,426	23,817	16.8%
	Non-MAAC Total	35,473	100.0%	128,398	100.0%	47,115	141,473	100.0%
All Areas	Total	57,022		196,860		76,387	207,892	

19 Percentages shown in Table 11-10 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 11-11, 21,524.9 MW are planning to deactivate by the end of calendar year 2019. A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through January 1, 2013, and it is expected that a total of 21,524.9 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through January 1, 2013, account for 8,453.2 MW, or 39.3 percent of retirements during this period. Units planning to retire in 2013 account for 237.4 MW, or 1.1 percent of retirements during this period. Overall, 3,951.1 MW, or 18.4 percent of all retirements from 2011 through 2019, are expected in the AEP zone.

Table 11-11 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,322.3
Retirements 2012	6,961.9
Retirements 2013	169.0
Planned Retirements 2013	237.4
Planned Retirements Post-2013	12,834.3
Total	21,524.9

Figure 11-1 Unit retirements in PJM: 2012 through 2019

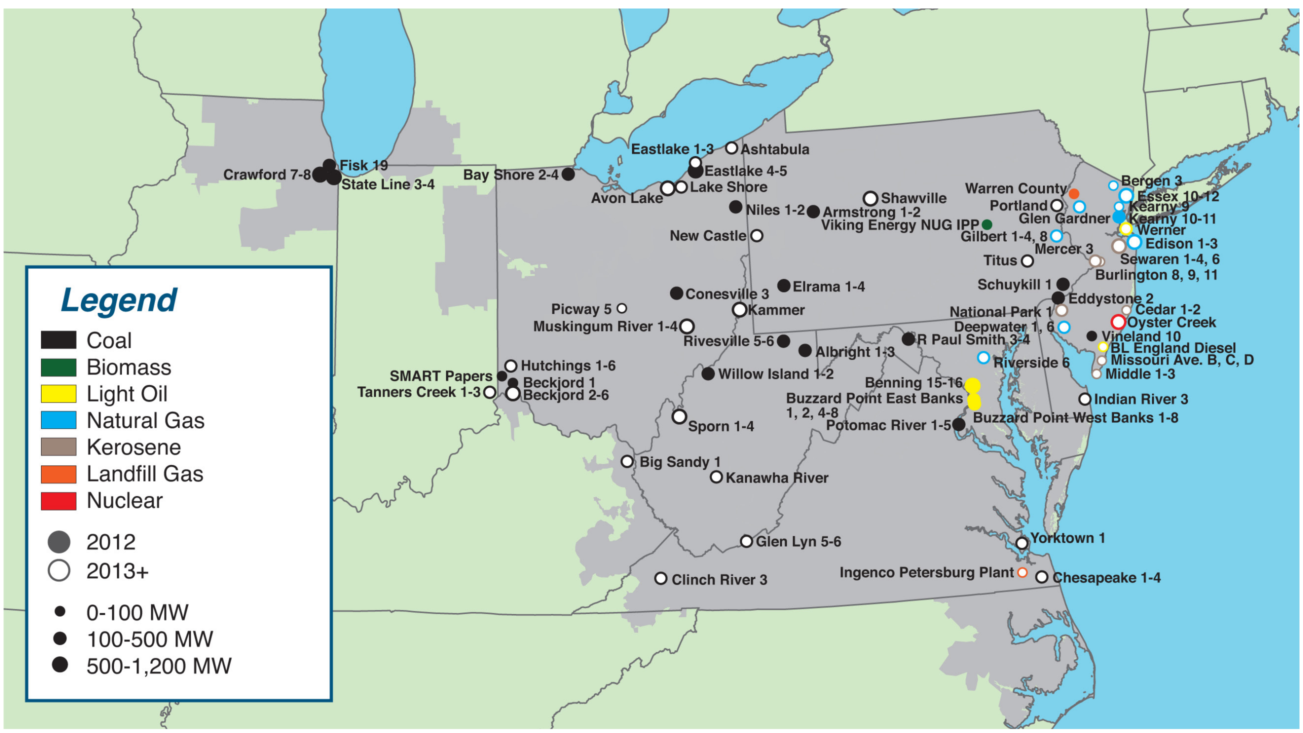


Table 11-12 Planned deactivations of PJM units after 2012, as of March 1, 2013

Unit	Zone	MW	Projected Deactivation Date
Warren County Landfill	JCPL	2.9	09-Jan-13
Ingenco Petersburg Plant	Dominion	2.9	31-May-13
Hutchings 4	DAY	61.9	01-Jun-13
Indian River 3	DPL	169.7	31-Dec-13
Riverside 6	BGE	115.0	01-Jun-14
Burlington 9	PSEG	184.0	01-Jun-14
Chesapeake 1-2	Dominion	222.0	31-Dec-14
Yorktown 1-2	Dominion	323.0	31-Dec-14
Portland	Met-Ed	401.0	07-Jan-15
Beckjord 2-6	DEOK	1,024.0	01-Apr-15
Avon Lake	ATSI	732.0	16-Apr-15
New Castle	ATSI	330.5	16-Apr-15
Titus	Met-Ed	243.0	16-Apr-15
Shawville	PENELEC	597.0	16-Apr-15
Gilbert 1-4, 8	JCPL	188.0	01-May-15
Glen Gardner	JCPL	160.0	01-May-15
Werner 1-4	JCPL	212.0	01-May-15
Kearny 9	PSEG	21.0	01-May-15
Cedar 1-2	AECO	67.7	31-May-15
Deepwater 1, 6	AECO	158.0	31-May-15
Middle 1-3	AECO	74.7	31-May-15
Missouri Ave B, C, D	AECO	60.0	31-May-15
Essex 12	PSEG	184.0	31-May-15
Big Sandy 2	AEP	278.0	01-Jun-15
Clinch River 3	AEP	230.0	01-Jun-15
Glen Lyn 5-6	AEP	325.0	01-Jun-15
Kammer	AEP	600.0	01-Jun-15
Kanawha River	AEP	400.0	01-Jun-15
Muskingum River 1-4	AEP	790.0	01-Jun-15
Picway 5	AEP	95.0	01-Jun-15
Sporn	AEP	580.0	01-Jun-15
Tanners Creek 1-3	AEP	488.1	01-Jun-15
Ashtabula	ATSI	210.0	01-Jun-15
Eastlake 1-3	ATSI	327.0	01-Jun-15
Lake Shore	ATSI	190.0	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	01-Jun-15
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 8, 11	PSEG	205.0	01-Jun-15
Edison 1-3	PSEG	504.0	01-Jun-15
Essex 10-11	PSEG	352.0	01-Jun-15
Mercer 3	PSEG	115.0	01-Jun-15
National Park 1	PSEG	21.0	01-Jun-15
Sewaren 1-4, 6	PSEG	558.0	01-Jun-15
BL England Diesels	AECO	8.0	01-Oct-15
Chesapeake 3-4	Dominion	354.0	31-Dec-15
Oyster Creek	JCPL	614.5	31-Dec-19
Total		13,071.7	

Table 11-13 HEDD Units in PJM as of January 1, 2013[20]

Unit	Zone	MW
Carlls Corner 1-2	AECO	72.6
Cedar Station 1-3	AECO	66.0
Cumberland 1	AECO	92.0
Mickleton 1	AECO	72.0
Middle Street 1-3	AECO	75.3
Missouri Ave. B,C,D	AECO	60.0
Sherman Ave.	AECO	92.0
Vineland West CT	AECO	26.0
Forked River 1-2	JCPL	65.0
Gilbert 4-7, 9, C1-C4	JCPL	446.0
Glen Gardner A1-A4, B1-B4	JCPL	160.0
Lakewood 1-2	JCPL	316.1
Parlin NUG	JCPL	114.0
Sayreville C1-C4	JCPL	224.0
South River NUG	JCPL	299.0
Werner C1-C4	JCPL	212.0
Bayonne	PSEG	118.5
Bergen 3	PSEG	21.0
Burlington 111-114, 121-124, 91-94, 8	PSEG	557.0
Camden	PSEG	145.0
Eagle Point 1-2	PSEG	127.1
Edison 11-14, 21-24, 31-34	PSEG	504.0
Elmwood	PSEG	67.0
Essex 101-104, 111-114, 121,124	PSEG	536.0
Kearny 9-11, 121-124	PSEG	446.0
Linden 1-2	PSEG	1,230.0
Mercer 3	PSEG	115.0
National Park	PSEG	21.0
Newark Bay	PSEG	120.2
Pedricktown	PSEG	120.3
Salem 3	PSEG	38.4
Sewaren 6	PSEG	105.0
Total		6,663.5

Actual Generation Deactivations in 2012

Table 11-14 shows unit deactivations for 2012 through January 1, 2013.[21] A total of 7,130.9 MW retired from January 1, 2012, through January 1, 2013, including 2,320 MW from FirstEnergy Corp, or 32.5 percent of these retirements. The retirements included 5,813.9 MW of coal steam generation, 788.0 MW of light oil generation, 250.0 MW of natural gas generation, 166.0 MW of heavy oil generation, 16.0 MW of wood waste generation and 3.0 MW of diesel generation. Of these retirements, 1,458.0 MW, or 20.4 percent, were in the ATSI zone

20 See "Current New Jersey Turbines that are HEDD Units," <http://www.state.nj.us/dep/workgroups/docs/apcrule_20110909turbinelist.pdf> (Accessed January 1, 2013)

21 *"PJM Generator Deactivations,"* PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (January 24, 2013).

Table 11-14 Unit deactivations: January 2012 through January 1, 2013

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
American Electric Power Company, Inc.	Sporn 5	440.0	Coal	AEP	51	Feb 13, 2012
Edison International	State Line 3	197.0	Coal	ComEd	56	Mar 25, 2012
Edison International	State Line 4	318.0	Coal	ComEd	51	Mar 25, 2012
GDF Suez	Viking Energy NUG	16.0	Wood Waste	PPL	24	Mar 31, 2012
Duke Energy Corporation	Walter C Beckjord 1	94.0	Coal	DEOK	59	May 01, 2012
Pepco Holdings, Inc.	Buzzard Point East Banks 1, 2, 4-8	112.0	Light Oil	Pepco	44	May 31, 2012
Pepco Holdings, Inc.	Buzzard Point West Banks 1-9	128.0	Light Oil	Pepco	44	May 31, 2012
Exelon Corporation	Eddystone 2	309.0	Coal	PECO	51	May 31, 2012
GenOn Energy, Inc.	Niles 2	108.0	Coal	ATSI	58	Jun 01, 2012
GenOn Energy, Inc.	Elrama 1	93.0	Coal	DLCO	60	Jun 01, 2012
GenOn Energy, Inc.	Elrama 2	93.0	Coal	DLCO	59	Jun 01, 2012
GenOn Energy, Inc.	Elrama 3	103.0	Coal	DLCO	57	Jun 01, 2012
Public Service Enterprise Group Incorporated	Kearny 10	122.0	Natural Gas	PSEG	42	Jun 01, 2012
Public Service Enterprise Group Incorporated	Kearny 11	128.0	Natural Gas	PSEG	42	Jun 01, 2012
Pepco Holdings, Inc.	Benning 15	275.0	Light Oil	Pepco	44	Jul 17, 2012
Pepco Holdings, Inc.	Benning 16	273.0	Light Oil	Pepco	40	Jul 17, 2012
Edison International	Crawford 8	319.0	Coal	ComEd	51	Aug 24, 2012
Edison International	Crawford 7	213.0	Coal	ComEd	54	Aug 28, 2012
Edison International	Fisk Street 19	326.0	Coal	ComEd	53	Aug 30, 2012
FirstEnergy Corp	Albright 1	73.0	Coal	APS	59	Sep 01, 2012
FirstEnergy Corp	Albright 2	73.0	Coal	APS	59	Sep 01, 2012
FirstEnergy Corp	Albright 3	137.0	Coal	APS	57	Sep 01, 2012
FirstEnergy Corp	Armstrong 1	172.0	Coal	APS	54	Sep 01, 2012
FirstEnergy Corp	Armstrong 2	171.0	Coal	APS	55	Sep 01, 2012
FirstEnergy Corp	R Paul Smith 3	28.0	Coal	APS	64	Sep 01, 2012
FirstEnergy Corp	R Paul Smith 4	87.0	Coal	APS	53	Sep 01, 2012
FirstEnergy Corp	Rivesville 5	35.0	Coal	APS	69	Sep 01, 2012
FirstEnergy Corp	Rivesville 6	86.0	Coal	APS	61	Sep 01, 2012
FirstEnergy Corp	Willow Island 1	53.0	Coal	APS	63	Sep 01, 2012
FirstEnergy Corp	Willow Island 2	164.0	Coal	APS	51	Sep 01, 2012
FirstEnergy Corp	Bay Shore 2	120.0	Coal	ATSI	53	Sep 01, 2012
FirstEnergy Corp	Bay Shore 3	119.0	Coal	ATSI	49	Sep 01, 2012
FirstEnergy Corp	Bay Shore 4	180.0	Coal	ATSI	44	Sep 01, 2012
FirstEnergy Corp	Eastlake 4	225.0	Coal	ATSI	56	Sep 01, 2012
FirstEnergy Corp	Eastlake 5	597.0	Coal	ATSI	40	Sep 01, 2012
City of Vineland	Howard Down 10	23.0	Coal	AECO	42	Sep 01, 2012
GenOn Energy, Inc.	Niles 1	109.0	Coal	ATSI	58	Oct 01, 2012
GenOn Energy, Inc.	Elrama 4	171.0	Coal	DLCO	51	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 1	88.0	Coal	Pepco	63	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 2	88.0	Coal	Pepco	62	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 3	102.0	Coal	Pepco	58	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 4	102.0	Coal	Pepco	56	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 5	102.0	Coal	Pepco	55	Oct 01, 2012
Smart Papers Holdings LLC	SMART Paper	24.9	Coal	DEOK	88	Oct 10, 2012
American Electric Power Company, Inc.	Conesville 3	165.0	Coal	AEP	50	Dec 31, 2012
Exelon Corporation	Schuylkill 1	166.0	Heavy Oil	PECO	54	Jan 01, 2013
Exelon Corporation	Schuylkill Diesel	3.0	Diesel	PECO	45	Jan 01, 2013

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.

On May 17, 2012, the PJM Board of Managers approved approximately $2 billion in transmission facilities upgrades, including more than 130 separate transmission upgrades.[22] The upgrades include upgrading existing transmission lines, constructing new transmission lines, installing new transformers, installing new substations, and adding capacitors and SVCs.

Transmission projects above $5 million are shown in Table 11-15, Table 11-16 and Table 11-17 for the Eastern, Western and Southern regions of PJM.

Table 11-15 Major upgrade projects in Eastern Region

Zone	Upgrade Description	Cost (Millions)
JCPL	Construct a new Whippany to Montville 230 kV line	$37.5
PENELEC	Convert the Lewis Run Farmers Valley 115 kV line to 230 kV	$46.8
PENELEC	Construct Farmers Valley 345/230 kV and 230/115 kV substation by looping the Homer City to Stolle Road 345 kV line into Farmers Valley	$29.5
PENELEC	Relocate the Erie South 345 kV line bay	$13.0
PENELEC	Construct a 115 kV ring bus at Claysburg Substation	$5.3
Pepco	Reconductor 230 kV line 23032 and 23034 with high temperature conductor	$16.0
PPL	Install a new North Lancaster 500/230 kV substation	$42.0

Table 11-16 Major upgrade projects in Western Region

Zone	Upgrade Description	Cost (Millions)
AEP	Install a new 765/345 substation at Mountaineer and build a ¾ mile 345 kV line to Sporn	$65.0
AEP	Add four 765 kV breakers at Kammer	$30.0
AEP	Reconductor Kammer West Bellaire 345 kV	$20.0
AEP	Terminate Transformer #2 at SW Lima in a new bay position	$5.0
APS	Loop the Homer City-Handsome Lake 345 kV line into the Armstrong substation and install a 345/138 kV transformer at Armstrong	$27.8
APS	Install a new Buckhannon Weston 138 kV line	$17.5
APS	Convert Moshannon substation to a four breaker 230 kV ring	$6.5
ATSI	Build a new Toronto to Harmon 345 kV line	$218.3
ATSI	Build a new Mansfield - Northfield Area 345 kV line	$184.5
ATSI	Convert Eastlake units 1, 2, 3, 4 and 5 to synchronous condensers	$100.0
ATSI	Build new Allen Jct - Midway - Lemoyne 345kV line	$86.3
ATSI	Create a new Harmon 345/138/69 kV substation by looping in the Star South Canton 345 kV line	$46.0
ATSI	Build a new Leroy Center 345/138 kV substation by looping in the Perry Harding 345 kV line	$46.0
ATSI	Build a new West Fremont Groton Hayes 138 kV line	$45.0
ATSI	Build a new Toronto 345/138 kV substation	$41.8
ATSI	Create a new Northfield Area 345 kV switching station by looping in the Eastlake Juniper 345 kV line and the Perry - Inland 345 kV line	$37.5
ATSI	Build a new 345-138kV Substation at Niles	$32.0
ATSI	Add a new 150 MVAR SVC and 100 MVAR capacitor at New Castle	$31.7
ATSI	Create a new Five Points Area 345/138 kV substation by looping in the Lemoyne Midway 345 kV line	$30.0
ATSI	Convert Lakeshore 18 to synchronous condensers	$20.0
ATSI	Build a new substation near the ATSI-AEP border and a new 138kV line from new substation to Longview	$17.7
ATSI	Re-conductor the Galion GM Mansfield Ontario - Cairns 138 kV line	$9.8
ATSI	Build a new Harmon Brookside + Harmon - Longview 138 kV line	$9.2
ATSI	Install a 345/138 kV transformer at the Inland Q-11 station	$7.2
ATSI	Install a 2nd 345/138 kV transformer at the Allen Junction station	$7.2
ATSI	Install a 2nd 345/138 kV transformer at the Bay Shore station	$7.2
ATSI	Reconductor the ATSI portion of South Canton Harmon 345 kV line	$6.0
DLCO	Install a third 345/138 kV transformer at Collier	$8.0

22 *"TEAC Recommendations to the PJM Board, May 2012,"* PJM.com <http://pjm.com/~/media/committees-groups/committees/teac/20120614/20120614-pjm-board-whitepaper.ashx> (Accessed January 30, 2013).

Table 11-17 Major upgrade projects in Southern Region

Zone	Upgrade Description	Cost (Millions)
Dominion	Rebuild Lexington to Dooms 500 kV line	$120.0
Dominion	Build a 500 MVAR SVC at Landstown 230 kV	$60.0
Dominion	Build new Surry to Skiffes Creek 500 kV line	$58.3
Dominion	Build new Skiffes Creek Whealton 230 kV line	$46.4
Dominion	Expand Yadkin 500/230 kV and 230/115 kV substation and Chesapeake 230/115 kV substation	$45.0
Dominion	Build new Skiffes Creek 500/230 substation	$42.4
Dominion	Build a new Suffolk to Yadkin 230 kV line	$40.0
Dominion	Add a third 500/230 kV transformer at Yadkin	$16.0
Dominion	Install a third 500/230 kV transformer at Clover	$16.0
Dominion	Install a second Valley 500/230 kV transformer	$16.0
Dominion	Upgrade Bremo Midlothian 230 kV line	$10.0
Dominion	Add six 500 kV breakers at Yadkin	$8.0

In August, 2012, the PJM Board of Managers cancelled the Potomac-Appalachian Transmission Highline (PATH) and Mid-Atlantic Power Pathway (MAPP) projects based on recommendations from Transmission Expansion Advisory Committee (TEAC) that were based in part on reductions in load growth.[23]

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.[24]

Transmission Planning Rules

In 2012, the Commission approved PJM proposed revisions to its planning process that removed some of its bright line aspects.[25] The Commission found that "the proposed revisions strike an appropriate balance between the need for PJM to maintain some flexibility given the scenario-based nature of the analysis in PJM's revised RTEP process and the need for sufficient detail in the tariff to allow stakeholders to participate in the planning process."[26] The Commission also found that the revisions "define a reasonable framework for its revised RTEP process while expanding the opportunities for stakeholder participation throughout its transmission planning process."[27] The Commission rejected arguments that rules lacked specific metrics and criteria for PJM to employ when evaluating the results of sensitivity studies and scenario analyses.[28] The Commission indicated that it may reconsider some of these changes in its review of PJM's Order No. 1000 compliance filing, now pending in FERC Docket No. ER13-198.

Competitive Grid Development

In Order No. 1000, the FERC requires regional transmission planning processes to modify the criteria for an entity to "propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a nonincumbent transmission developer."[29,30] Such criteria "must not be unduly discriminatory or preferential."[31]

Order No. 1000 requires, among other things, that each public utility transmission provider (including PJM) remove from its FERC approved tariff and agreements, as necessary and subject to certain limitations, a federal right of first refusal (ROFR) for certain new transmission projects.[32] ROFR would continue to apply to transmission projects not included in a regional transmission plan for purposes of cost allocation, and ROFR would continue apply to upgrades to transmission facilities.[33]

Order No. 1000 allows, but does not require, competitive bidding to solicit transmission projects or developers.[34] The rule does not override or otherwise affect state or local laws concerning construction of transmission facilities, such as siting or permitting.[35]

On October 25, 2012, PJM submitted a filing in compliance with Order No. 1000.[36] PJM adopted a sponsorship model and made some organizational changes to the process, including defining three categories of projects, Long-lead projects, Short-term Projects and Immediate-need Reliability Projects, and applying different procedural rules to each.[37]

The MMU filed a protest complaining that PJM's proposal continued to lack definition to key terms that

23 See PJM.com. "Potomac – Appalachian Transmission Highline (PATH) <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/path.aspx>(Accessed November 1, 2012).
24 See PSEG.com. "Susquehanna-Roseland line receives final federal approval) <http://www.pseg.com/info/media/newsreleases/2012/2012-10-02.jsp> (Accessed November 1, 2012).
25 139 FERC ¶ 61,080 (April 30, 2012), order accepting compliance filing, 141 FERC ¶ 61,160 (November 29, 2012).
26 141 FERC ¶ 61,160 at P 21.
27 *Id.* at P 21.
28 *Id.* at P 22.
29 Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011).
30 Order No. 1000 at PP 323–327.
31 *Id.* at PP 323–324.
32 *Id.* at PP 313–322.
33 *Id.* at PP 318–319.
34 *Id.* at P 321 & n.302.
35 *Id.* at PP 337, 339.
36 PJM Compliance in RM10-23, FERC Docket No. ER13-198 ("Order 1000 Compliance Filing").
37 Order 1000 Compliance Filing at 13–14.

affect the evaluation of projects and did not allow for meaningful competition on project costs.[38] The MMU is concerned that the process continues to contain shortcomings evident in RTEP consideration of certain projects proposed by Primary Power, which lead to litigation. That litigation was resolved in an order on complaint that found that PJM has followed the current rules when awarding to incumbents certain projects contested by Primary Power.[39] The MMU filed comments in that proceeding, observing, "There does not appear to have been a process that would have permitted direct competition between Primary Power and the Incumbents."[40] The MMU also pointed out that Primary Power's complaint demonstrated that the concepts of sponsorship, upgrades and new versus revised projects needed clarification.[41] The Commission explained that it "stated in Order No. 1000 that the public utility transmission providers in a region may, but are not required to, use competitive solicitation to solicit project or project developers to meet regional needs."[42]

The MMU also recommended to the Commission that PJM include in its Order No. 1000 compliance filing provisions that would allow competition to finance projects, without regard to who proposes them, or who builds them or owns them.[43]

38 Comments of the Independent Market Monitor for PJM, Docket No. ER13-198 (December 10, 2012) ("December 10th IMM Comments").
39 140 FERC ¶ 61,054 at P 69 (July 19, 2012).
40 Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM, Docket No. EL12-69-000 (June 22, 2012).
41 *Id.* at 3–4.
42 140 FERC ¶ 61,054 at P 83.
43 *See* December 10th IMM Comments at 4–7.

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.

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 which creates the funds available to offset congestion costs in an LMP market.[2]

In PJM, Financial Transmission Rights (FTRs) were part of the market design, and FTRs were available to network service and long-term, firm, point-to-point transmission service customers as an offset to congestion costs, from the inception of locational marginal pricing (LMP) on April 1, 1998.[3]

Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of Auction Revenue Rights (ARRs) and an associated Annual FTR Auction.[4,5] Since then, all PJM members have been eligible to purchase FTRs in auctions. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs. FTR funding has been based on both day ahead and balancing congestion revenues from its initial design.

PJM created the split between ARRs and FTRs in order to both continue to provide the appropriate protection against congestion for load, and to permit any excess transmission capacity on the system to be made available to those market participants who wished to use FTRs to speculate or to hedge positions. This separation substantively changed the definition of FTRs. FTRs no longer represent the rights of load to the congestion offset associated with the physical transmission system, but instead represent the potential offset to congestion costs associated with the excess capability of the transmission system to deliver energy over and above that assigned to ARRs. As a result, the meaning of FTRs in PJM is different from the meaning of FTRs in other ISOs and RTOs that have only FTRs but no ARRs. In PJM, the separation of ARRs and FTRs meant that FTRs were provided as a market enhancement for market participants that did not serve load and did not receive an allocation of FTRs. But FTRs now no longer represent the financial equivalent of physical rights associated with the transmission system. That is what ARRs represent. There is no obligation to provide a specific level of FTRs, in excess of the level of ARRs, and there is no obligation to ensure that FTRs receive any specific level of revenue. FTRs are now a market product and the value of FTRs to market participants will be reflected in the price participants are willing to pay for them.

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. 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.

The *2012 State of the Market Report for PJM* focuses on the Long Term FTR Auctions, the Annual FTR Auctions and the Monthly Balance of Planning Period

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259–62,260 & n. 123.
3 *Id.*
4 102 FERC ¶ 61,276 (2003).
5 87 FERC ¶ 61,054 (1999).

FTR Auctions during the 2012 to 2013 planning period, which covers January 1, 2012, through December 31, 2013.

Table 12-1 The FTR Auction Markets results were competitive

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

- The 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.
- 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 effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism. Nonetheless there is a growing issue with FTR revenue sufficiency.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2013 to 2016 Long Term FTR Auction include the Gainesville Transformer, approximately 40 miles west of Washington, D.C., and the Monticello – East Winamac Flowgate, approximately 120 miles north of Indianapolis, IN. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2012 to 2013 planning period include the Cumberland Ave – Bush Flowgate, approximately 100 miles northwest of Indianapolis, IN and the Stephenson – Stonewall Flowgate, approximately 100 miles northwest of Washington, D.C. The geographic location of these constraints is shown in Figure 12-1.

  Market participants can also sell FTRs. In the 2013 to 2016 Long Term FTR Auction, total participant FTR sell offers were 211,316 MW, down from 251,290 MW during the 2012 to 2015 Long Term FTR Auction. In the Annual FTR Auction for the 2012 to 2013 planning period, total participant FTR sell offers were 356,299 MW, up from 337,510 MW during the 2011 to 2012 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2012) of the 2012 to 2013 planning period, total participant FTR sell offers were 3,589,825 MW, down from 3,984,782 MW for the same period during the 2011 to 2012 planning period.

- **Demand.** The PJM tariff specifies that PJM has the authority to limit the maximum number of FTR bids to 5,000 per participant for a monthly auction, or a single round of an annual auction, if necessary to avoid related system performance issues.[6] On this basis, PJM currently limits the maximum number of bids that could be submitted by a participant for any individual period in an auction to 10,000 bids.

  In the 2013 to 2016 Long Term FTR Auction, total FTR buy bids increased 15.5 percent from 2,400,881 MW to 2,772,621 MW. In the Annual FTR Auction total FTR buy bids and self-scheduled bids decreased 21.4 percent from 3,260,695 MW to 2,561,835 MW. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2012 to 2013 (June through December 2012) planning period increased 16.8 percent from 12,767,075 MW for the same time period of the prior planning period, to 14,906,684 MW.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2012 to 2013 Annual FTR Auction was low for peak and off peak FTR obligations and moderately concentrated for 24-hour FTR obligations. The ownership concentration was also moderately concentrated for peak and off peak FTR buy bid options and highly concentrated for 24-hour FTR buy bid options for the same time period. The level of concentration is descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction.

6 OA Schedule 1 § 7.3.5(d).

For the 2013 through 2016 Long Term FTR Auction, financial entities purchased 80.4 percent of prevailing flow FTRs and 91.9 percent of counter flow FTRs. In the Annual FTR Auction, planning period 2012 through 2013, financial entities purchased 55.8 percent of prevailing flow FTRs and 77.8 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 81.1 percent of prevailing flow and 84.6 percent of counter flow FTRs for 2012. Financial entities owned 62.8 percent of all prevailing and counter flow FTRs, including 54.4 percent of all prevailing flow FTRs and 80.1 percent of all counter flow FTRs during the same time period.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first seven months of the 2012 to 2013 planning period were $398,630.
- **Credit Issues.** Twenty participants defaulted during 2012 from twenty one default events. The average of these defaults was $381,772 with nine based on inadequate collateral and eleven based on nonpayment. The average collateral default was $790,300 and the average nonpayment default was $47,522. The majority of these defaults were promptly cured. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** The 2013 to 2016 Long Term FTR Auction cleared 290,700 MW (10.5 percent of demand) of FTR buy bids, compared to 259,885 MW (10.8 percent) in the 2012 to 2015 Long Term FTR Auction. The 2013 to 2016 Long Term FTR Auction also cleared 56,692 MW (26.8 percent) of FTR sell offers, up from 31,288 MW (12.5 percent) in the 2012 to 2015 Long Term FTR Auction.

  For the 2012 to 2013 planning period, the Annual FTR Auction cleared 371,295 MW (14.5 percent) of FTR buy bids, compared to 387,743 MW (11.9 percent) for the 2011 to 2012 planning period. The 2012 to 2013 Annual FTR Auction also cleared 35,275 MW (9.9 percent) of FTR sell offers for the 2012 to 2013 planning period, up from 24,960 MW (7.4 percent) for the 2011 to 2012 planning period.

  For the first seven months of the 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,437,437 MW (9.6 percent) of FTR buy bids and 484,697 MW (13.5 percent) of FTR sell offers.

- **Price.** In the 2013 to 2016 Long Term FTR Auction, 95.9 percent of FTRs were purchased for less than $1 per MW, down from 96.5 percent in the previous Long Term FTR Auction. The weighted-average price for 24-hour buy bids in the Long Term FTR Auction remained constant at $0.36 per MW. Counter flow buy bid prices were negative, but approximately equal in magnitude, than prevailing flow FTR bid prices.

  For the 2012 to 2013 Annual Auction, 90.4 percent of FTRs were purchased for less than $1 per MW, up from 87.1 percent in the previous Annual FTR Auction. The weighted-average price for 24-hour buy bid obligations in the 2012 to 2013 planning period was $0.40 per MW, down from $0.68 in the 2011 to 2012 planning period.

  The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2012 to 2013 planning period was $0.12, down from $0.13 per MW in the first seven months of the 2011 to 2012 planning period.

- **Revenue.** The 2013 to 2016 Long Term FTR Auction generated $28.6 million of net revenue for all FTRs, up from $20.5 million in the 2012 to 2015 Long Term FTR Auction.

  The 2012 to 2013 planning period Annual FTR Auction generated $602.9 million of net revenue for all FTRs, down from $1,029.7 million for the 2012 to 2013 planning period.

  The Monthly Balance of Planning Period FTR Auctions generated $17.3 million in net revenue for all FTRs for the first seven months of the 2012 to 2013 planning period, down from $21.9 million for the same time period in the 2011 to 2012 planning period.

- **Revenue Adequacy.** FTRs were paid at 80.6 percent of the target allocation for the 2011 to 2012 planning period.[7] FTRs were paid at 74.8 percent of the target

7 Unless specifically noted, payout ratios reported in this section are calculated using PJM's method and are consistent with PJM's reported payout ratios.

allocation level for the first seven months of the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $335.1 million of FTR revenues during the first seven months of the 2012 to 2013 planning period and $799.4 million during the 2011 to 2012 planning period. For the first seven months of the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were Northern Illinois Hub and Quad Cities 1. Similarly, the top sink and top source with the largest negative FTR target allocations were Quad Cities 2 and Eastern 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 -$7.6 million in profits for physical entities, of which $151.3 million was from self-scheduled FTRs, and $78.8 million for financial entities. FTR profits generally increased in the summer and winter months when congestion was higher and decreased in the shoulder months when congestion was lower. As shown in Table 12-19, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in 2012. Prevailing flow FTRs, purchased by financial entities, were not profitable in 2012.

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2012 to 2013 planning period were the Pleasant Prairie – Zion Flowgate, approximately 60 miles south of Milwaukee, WI, and the Breed – Wheatland Flowgate, approximately 120 miles west of Indianapolis, IN. The geographic location of these constraints is shown in Figure 12-1. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation.

- **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. In the 2012 to 2013 planning period PJM allocated a total of 9,647.6 MW with a total target allocation of $3,471,223.

- **Demand.** Total requested volume in the annual ARR allocation was 164,770 MW for the 2012 to 2013 planning period with 64,160 MW requested in Stage 1A, 27,325 MW requested in Stage 1B and 57,053 MW requested in Stage 2. This is up from 148,538 MW for the 2011 to 2011 planning period with 64,160 MW requested in Stage 1A, 22,208 MW requested in Stage 1B and 57,053 MW requested in Stage 2. The ATSI integration accounted for 5,434 MW of increased demand. The total ARR volume allocated is limited by the amount of network service and firm point-to-point transmission service. Several constraints were over allocated in the 2012 to 2013 Stage 1A ARR Allocation, consistent with the tariff, with a total over allocation of 892 MW.

- **Stage 1A Infeasibility.** In the 2012 to 2013 planning period PJM was required, per the PJM OATT Section 7.4.2 (i) to artificially increase the modeled line ratingsof several facilities over their physical capability, to accommodate Stage 1A ARR requests in the ARR Allocation model. The ultimate result of these increased line ratings is an over allocation of ARRs, which contributes to FTR underfunding. PJM was required to increase capability on nine separate facilities for a total of 892 MW.

- **ARR Reassignment for Retail Load Switching.** There were 22,543 MW of ARRs associated with approximately $226,900 of revenue that were reassigned in the first seven months of the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758,900 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Market Performance

- **Volume.** Of 164,770 MW in ARR requests for the 2012 to 2013 planning period, 97,986 MW (59.5 percent) were allocated. Market participants self scheduled 40,195 MW (45.1 percent) of these allocated ARRs as Annual FTRs. Of 148,538 MW in ARR requests for the 2011 to 2012 planning period, 102,476 MW (69.0 percent) were allocated. Market participants self scheduled 46,017 MW (44.9 percent) of these allocated ARRs as Annual FTRs.
- **Revenue.** There are no ARR revenues. ARRs are allocated to qualifying customers because they pay for the transmission system.
- **Revenue Adequacy.** For the first seven months in the 2012 to 2013 planning period, the ARR target allocations were $565.4 million while PJM collected $620.2 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through December 31, 2012, making ARRs revenue adequate. For the 2011 to 2012 planning period, the ARR target allocations were $982.9 million while PJM collected $1,091.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.
- **ARR Proration.** Stage 1A ARR requests may not be prorated. As a result, several facilities were overallocated for a total of 892 MW. Of the requested ARRs for Stage 1B, 11,581 MW were prorated and of the requested ARRs for Stage 2, 55,201 MW were prorated for the 2012 to 2013 planning period. For the 2011 to 2012 planning period Stage 1A was not prorated nor overallocated. Some of the requested ARRs for the 2011 to 2012 planning period were prorated in Stage 1B and Stage 2 as a result of binding transmission constraints.
- **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 2012 to 2013 planning period, the total revenues received by ARR holders, including self-scheduled FTRs, offset 82.1 percent of the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 88.8 percent of the total congestion costs within PJM and for the 2010 to 2011 planning period 97.3 percent.

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. 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.

Revenue adequacy received a lot of attention in the PJM FTR market in 2012. 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. 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 the differences between modeling in the day ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The payout ratio reported by PJM is understated. The reported payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs. For 2012 the reported payout ratio is 73.5 percent while the correctly calculated payout ratio is 76.9 percent. The MMU recommends that the calculation of the 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.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in 2012 would have been 88.1 percent instead of the reported 73.5 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 2012 from the reported 73.5 percent to 91.2 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 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; 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; the overallocation of ARRs; the appropriateness of seasonal ARR allocations; and the role of up-to congestion transactions. The MMU recommends that these issues be reviewed and modifications implemented where possible. Funding issues that persist as a result of modeling differences should be borne by FTR holders operating in the voluntary FTR market.

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.[8] 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.

8 For additional information on marginal losses, see the *2011 State of the Market Report for PJM*, Volume II, Section 10, "Congestion and Marginal Losses," at "Marginal Losses."

Revenues above that level on individual FTR paths are used to fund FTRs on paths which received less than their target allocations.

FTR funding is not on a path specific basis or on a time specific basis. There are 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. 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 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 FTR class type 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 three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. 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 class types. FTR self-scheduled bids are available only as obligations and 24-hour class types, 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.[9] FTRs can also be traded between market participants through bilateral

9 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 38.

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. 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.[10] 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 not be planned in advance or may be emergency in nature. In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration which do not overlap in time. The choice of which to model may have significant distributional consequences.

Long Term FTR Auctions

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system capability assuming that all ARRs allocated in the prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The 2009 to 2012 and 2010 to 2013 Long Term FTR Auctions consisted of two rounds.[11] The 2011 to 2014 and 2012 to 2015 Long Term FTR Auctions consisted of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained in the Long Term Auctions may have terms of any one year or a single term of all three years. FTR products available in the Long Term Auction include 24-hour, on peak and off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- **Round 1.** The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink.
- **Round 2.** The second round is conducted approximately three months after the first round and follows the same rules as Round 1.
- **Round 3.** The third round is conducted approximately six months after the first round and follows the same rules as Round 1.

Table 12-2 and Table 12-3 list the top binding constraints in order of the marginal value of the binding constraint during on peak hours. The marginal value measures the value gained by relieving a constraint by 1 MW and is computed for both peak and off peak hours.[12]

Table 12-2 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2013 to 2016

			Severity Ranking by Auction Round		
Constraint	Type	Control Zone	1	2	3
Gainesville	Transformer	Dominion	1	1	NA
Monticello - East Winamac	Flowgate	MISO	3	2	1
Oak Grove - Galesburg	Flowgate	MISO	2	NA	NA
Bremo - Kidds Store	Line	Dominion	4	389	NA
Berlin - Silver Lake	Line	AEP	5	NA	NA
Laurel Ave. - Roseland	Line	PSEG	6	9	NA
Cumberland Ave - Bush	Flowgate	MISO	111	4	3
North Seaford - Taylor	Line	DPL	7	158	NA
Middlebourne - Willow	Line	AP	283	5	NA
Gordonsville	Transformer	Dominion	11	NA	4

Annual FTR Auctions

After the Long Term FTR Auction, residual capability on the PJM transmission system is auctioned in the Annual FTR Auction. Annual FTRs are effective beginning June 1 of the planning period through May 31. Outages expected to last two or more months are included in the determination of the simultaneous feasibility for the Annual FTR Auction. ARR holders who wish to self schedule must inform PJM prior to round one of this auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. This auction consists of four rounds that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold.

10 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 54.

11 FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

12 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 57.

FTRs in this auction can be obligations or options for peak, off peak or 24-hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Figure 12-1 shows the geographic location of the top ten binding constraints from the 2013 to 2016 Long Term FTR Auction, the 2012 to 2013 Annual FTR Auction and the 2012 to 2013 Annual ARR allocation. Many of the top binding constraints are flowgates and the binding constraints are primarily concentrated near the PJM-MISO border.

Figure 12-1 Geographic location of top ten binding constraints for the 2013 to 2016 Long Term and 2012 to 2013 Annual FTR Auctions and 2012 to 2013 Annual ARR allocation

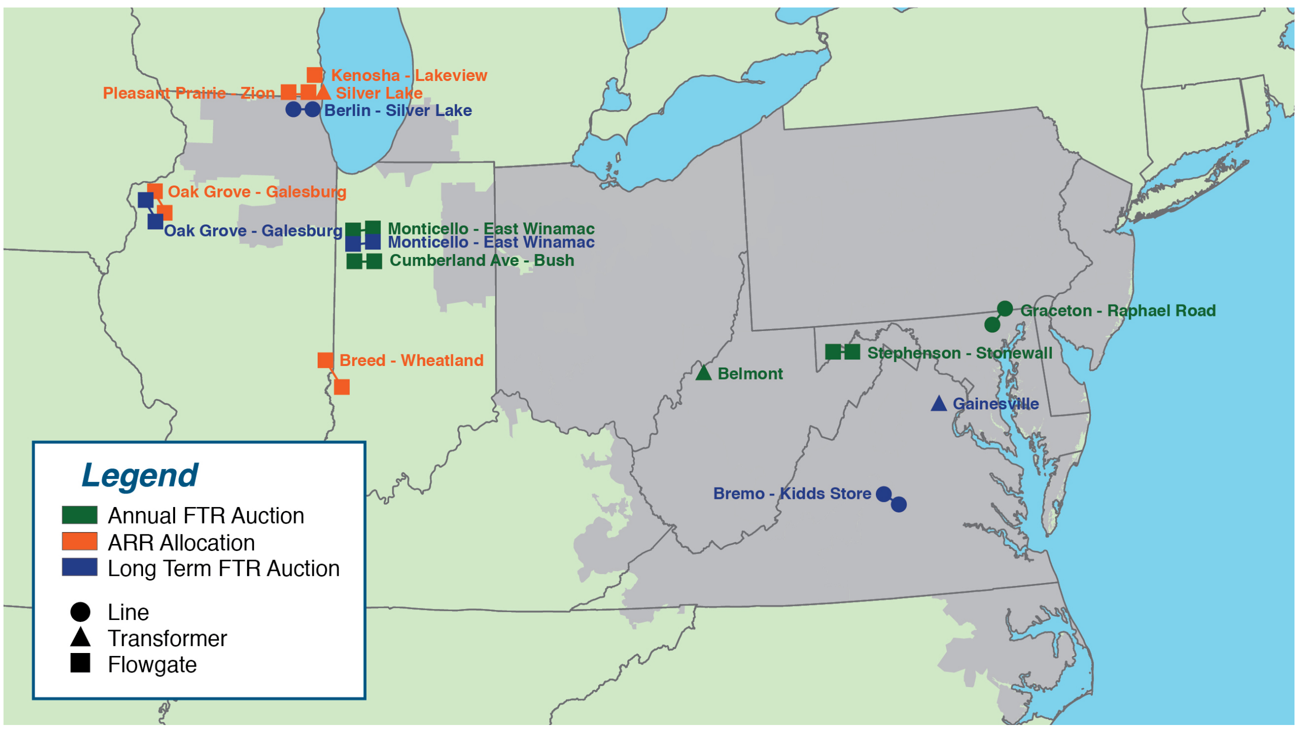


Table 12-3 shows the top 10 binding constraints for the 2012 to 2013 Annual FTR Auction based on the marginal value of on peak hours.

Table 12-3 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2012 to 2013

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Cumberland Ave - Bush	Flowgate	MISO	1	1	1	1
Stephenson - Stonewall	Line	AP	2	2	2	2
Monticello - East Winamac	Flowgate	MISO	6	3	3	3
Graceton - Raphael Road	Line	BGE	9	5	4	4
Belmont	Transformer	AP	3	4	5	8
Michigan City - Laporte	Line	AEP	4	8	8	12
Doubs	Transformer	AP	5	7	7	7
Stillwell	Flowgate	MISO	NA	159	NA	6
Lanesville	Flowgate	MISO	7	9	10	9
Zion	Transformer	ComEd	8	6	6	NA

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 withdraws. 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 customers or PJM members 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 or off peak products.[13]

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

In the 2013 to 2016 Long Term FTR Auction, total FTR cleared buy bids increased 11.9 percent to 290,700 MW. In the Annual FTR Auction, total cleared FTR buy bids and self-scheduled bids decreased 4.2 percent to 371,295 MW. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2012 to 2013 planning period decreased 9.6 percent to 1,437,438 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. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly Balance of Planning Period FTR Auctions or the secondary bilateral market.

The ownership concentration of cleared FTR buy bids resulting from the 2012 to 2013 Annual FTR Auction was low for peak and off peak FTR obligations and moderately concentrated for 24-hour FTR obligations. The ownership concentration was highly concentrated for 24-hour buy bid options, but only moderately concentrated for peak and off peak FTR buy bid options for the same time period.

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 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 12-4 presents the 2013 to 2016 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 80.4 percent of prevailing flow buy bid FTRs and 91.9 percent of counter flow buy bid FTRs with the result that financial entities purchased 85.5 percent of all Long Term FTR Auction cleared buy bids for the 2013 to 2016 Long Term FTR Auction.

13 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 39.

Table 12-4 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2013 to 2016

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	19.6%	8.1%	14.5%
	Financial	80.4%	91.9%	85.5%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	3.3%	1.7%	2.7%
	Financial	96.7%	98.3%	97.3%
	Total	100.0%	100.0%	100.0%

Table 12-5 presents the Annual FTR Auction cleared FTRs for the 2012 to 2013 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2012 to 2013 planning period, financial entities purchased 55.8 percent of prevailing flow FTRs and 77.8 percent of counter flow FTRs with the result that financial entities purchased 61.8 percent of all Annual FTR Auction cleared buy bids for the 2012 to 2013 planning period.

Table 12-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2012 to 2013

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	14.9%	1.5%	11.2%
		No	29.3%	20.7%	26.9%
		Total	44.2%	22.2%	38.2%
	Financial	No	55.8%	77.8%	61.8%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		12.5%	4.8%	9.5%
	Financial		87.5%	95.2%	90.5%
	Total		100.0%	100.0%	100.0%

Table 12-6 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through June 2012 by trade type, organization type and FTR direction. Financial entities purchased 81.1 percent of prevailing flow and 84.6 percent of counter flow FTRs for 2012 with the result that financial entities purchased 60.5 percent of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through December 2012.

Table 12-6 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through December 2012

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	18.9%	15.4%	17.5%
	Financial	81.1%	84.6%	82.5%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	22.4%	8.0%	18.4%
	Financial	77.6%	92.0%	81.6%
	Total	100.0%	100.0%	100.0%

Table 12-7 presents the daily FTR net position ownership for January through December 2012 by FTR direction.

Table 12-7 Daily FTR net position ownership by FTR direction: January through December 2012

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	45.6%	19.9%	37.2%
Financial	54.4%	80.1%	62.8%
Total	100.0%	100.0%	100.0%

Integration of DEOK

On January 1, 2012, the Duke Energy Ohio and Kentucky (DEOK) zone was integrated into PJM. DEOK zonal customers were eligible to participate in a direct allocation of FTRs effective from January 1, 2012 through May 31, 2012. In addition, on June 1, 2011 the American Transmission Systems, Inc. (ATSI) zone was integrated into PJM. Eligible customers in this zone participated in the 2011 to 2012 Annual ARR Allocation or elected to receive a direct allocation of FTRs instead of ARRs. For both the ATSI and DEOK zones a transitional period of two planning periods was established during which participants with firm transmission service that sources or sinks in these zones may elect to receive directly allocated FTRs instead of ARRs. Table 12-8 shows the direct allocation of FTRs in the DEOK zone for the 2011 to 2012 planning period. This FTR volume is not included in the monthly auction data. In the DEOK zone, 5,396 MW of FTRs were requested with 4,616 MW (86 percent) cleared. These FTRs were effective only from the date of integration to the end of the planning period, January 1, 2012 through May 31, 2012.

Table 12-8 Directly allocated FTR volume for DEOK Control Zone: January 1, 2012 through May 31, 2012[14]

Planning Period*	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2011/2012	519	5,396	4,616	86%	781	14%

*Effective January 1, 2012 through May 31, 2012

Table 12-9 shows the FTRs directly allocated to participants in the ATSI and DEOK Control Zones for the 2012 to 2013 planning period. Participants requested 9,902.7 MW and 2,257.7 MW of FTRs in the ATSI and DEOK zones with 4,874.8 MW (49.2 percent) and 545.5 MW (24.2 percent) clearing.

Table 12-9 Directly allocated FTR volume for ATSI and DEOK Control Zones: Planning period 2012 to 2013

Zone	Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
ATSI	324	9,902.7	4,874.8	49.2%	5,027.9	50.8%
DEOK	78	2,257.7	545.5	24.2%	1,712.2	75.8%

Market Behavior

FTR Forfeitures

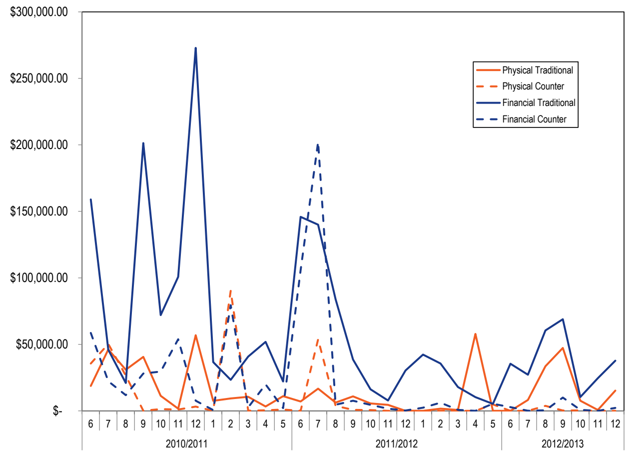
An FTR holder may be subject to forfeiture of any profits from an FTR if it meets the criteria defined in Section 5.2.1 (b) of Schedule 1 of the PJM Operating Agreement. If a participant has a cleared increment offer or decrement bid for an applicable hour at or near the source or sink of any FTR they 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 12-2 shows the FTR forfeitures values for both counter flow and prevailing flow FTRs for each month of June 2010 through December 2012 by company type.

14 The volume data presented in Table 12-8 are not included in the monthly FTR ownership, volume or revenue data.

Total forfeitures for the first seven months of the 2012 to 2013 planning period were $398,630.

Figure 12-2 Monthly FTR Forfeitures for physical and financial participants: June 2010 through December 2012



Credit Issues

The credit issues reported here were not necessarily related to FTR positions.

In June 2012, PJM processed $38 million of billing adjustments associated with marginal loss surplus allocations. These billing adjustments required participants to repay refunds which had been previously ordered by FERC and subsequently reversed by FERC. Five of the companies required to repay the allocation defaulted based on inadequate collateral and fifteen defaulted on payment of their billing adjustments, totaling $28.3 million in defaults. One company cured its payment default. Default Allocation Assessments were included in the next monthly bill for non-defaulted members to cover the unpaid billing adjustments. Twenty five additional members defaulted on $96,000 of their payment obligations resulting from these billed Default Allocation Assessments.

In addition, unrelated to the marginal loss surplus billing adjustments, twenty participants defaulted during 2012 from twenty one default events. The average of these defaults was $381,772, with nine based on inadequate collateral and eleven based on nonpayment. The average collateral default was $790,300 and the average nonpayment default was $47,522. The majority of these defaults were promptly cured.

As reported in a filing to FERC on April 23, 2012, PJM terminated RTP Controls, Inc's membership due to a credit default effective March 9, 2012.[15] RTP Controls was declared in default three times within a twelve month period, and in accordance with sections 15.1.6(c) and 4.1(c) of the Operating Agreement its membership was terminated and its forward market positions liquidated.

Market Performance

Volume

Table 12-10 shows the 2013 to 2016 Long Term FTR Auction volume by trade type, FTR direction and period type.[16] The total volume was 2,481,922 MW for FTR buy bids and 154,624 MW for FTR sell offers in the 2013 to 2016 Long Term FTR Auction. This represents a 3.4 percent increase in buy bids and a 31.6 percent increase in FTR sell offers over the 2012 to 2015 Long Term FTR Auction.

Table 12-10 Long Term FTR Auction market volume: Planning periods 2013 to 2016

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	52,950	207,509	52,684	25.4%	154,825	74.6%
		Year 2	40,530	162,112	36,608	22.6%	125,504	77.4%
		Year 3	37,900	155,688	38,375	24.6%	117,312	75.4%
		Year All	428	2,914	1,800	61.8%	1,114	38.2%
		Total	131,808	528,223	129,467	24.5%	398,756	75.5%
	Prevailing Flow	Year 1	147,937	855,264	64,251	7.5%	791,012	92.5%
		Year 2	120,754	681,666	47,737	7.0%	633,929	93.0%
		Year 3	117,194	662,370	48,634	7.3%	613,735	92.7%
		Year All	7,369	45,099	610	1.4%	44,489	98.6%
		Total	393,254	2,244,398	161,232	7.2%	2,083,166	92.8%
	Total		525,062	2,772,621	290,700	10.5%	2,481,922	89.5%
Sell offers	Counter Flow	Year 1	14,863	47,888	11,436	23.9%	36,452	76.1%
		Year 2	8,849	32,052	9,174	28.6%	22,878	71.4%
		Year 3	4,259	10,657	691	6.5%	9,967	93.5%
		Year All	NA	NA	NA	NA	NA	NA
		Total	27,971	90,597	21,300	23.5%	69,296	76.5%
	Prevailing Flow	Year 1	18,949	69,609	20,390	29.3%	49,219	70.7%
		Year 2	10,849	41,737	13,619	32.6%	28,118	67.4%
		Year 3	3,822	9,373	1,382	14.7%	7,991	85.3%
		Year All	NA	NA	NA	NA	NA	NA
		Total	33,620	120,719	35,391	29.3%	85,327	70.7%
	Total		61,591	211,315	56,692	26.8%	154,624	73.2%

The 2013 to 2016 Long Term FTR Auction cleared 290,700 MW (10.5 percent) of FTR buy bids, compared to 259,885 MW (10.8 percent) in the previous Long Term FTR Auction. The 2012 to 2015 Long Term FTR Auction also cleared 56,692 MW (26.8 percent) of FTR sell offers, compared to 31,288 MW (12.5 percent) in the previous Long Term FTR Auction.

The volume of buy bids for the period covering all three years of the Long Term FTR Auction was 49,013 MW for both prevailing and counter flow FTRs, with a total of 2,400 MW clearing (4.9 percent). In the previous Long Term FTR Auction the buy bids for the three year FTR were 830 MW with none clearing, representing a 580.5 percent increase in buy bids for the 2013 to 2016 planning periods.

In the 2013 to 2016 Long Term FTR Auction 129,467 MW (24.5 percent of demand; 44.5 percent of total FTR volume) of counter flow FTR buys bids and 161,232 MW (10.5 percent of demand; 55.5 percent of total FTR volume) of prevailing flow FTR buy bids cleared. In the 2013 to 2016 Long Term FTR Auction, there were 90,597 MW (23.5 percent) of counter flow sell offers and 35,391 MW (29.3 percent) of prevailing flow sell offers cleared.

In the Annual FTR Auction for the 2012 to 2013 planning period, total participant FTR sell offers were 356,299 MW, up 5.6 percent from the 2011 to 2012 planning period, and total FTR buy bids were 2,561,835 MW, down 21.4 percent from the 2011 to 2012 planning period. For the 2012 to 2013 planning period 371,295 MW (14.5 percent) of buy bids cleared, down 4.2 percent from the previous planning period, and 35,275 MW (9.9 percent) of sell offers cleared, up 41.3 percent from the previous planning period.

Table 12-11 provides the Annual FTR Auction market volume for the 2012 to 2013 planning period.

15 Burlew, James. Letter to Honorable Kimberly D. Bose. April 23, 2012.

16 Calculated values shown in Section 12, "Financial Transmission and Auction Revenue Rights," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 12-11 Annual FTR Auction market volume: Planning period 2012 to 2013

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	74,408	357,104	100,369	28.1%	256,735	71.9%
		Prevailing Flow	185,534	1,271,013	186,286	14.7%	1,084,727	85.3%
		Total	259,942	1,628,116	286,655	17.6%	1,341,462	82.4%
	Options	Counter Flow	172	13,006	0	0.0%	13,006	100.0%
		Prevailing Flow	28,074	878,996	42,924	4.9%	836,073	95.1%
		Total	28,246	892,002	42,924	4.8%	849,079	95.2%
	Total	Counter Flow	74,580	370,110	100,369	27.1%	269,741	72.9%
		Prevailing Flow	213,608	2,150,009	229,209	10.7%	1,920,800	89.3%
		Total	288,188	2,520,119	329,578	13.1%	2,190,541	86.9%
Self-scheduled bids	Obligations	Counter Flow	259	1,522	1,522	100.0%	0	0.0%
		Prevailing Flow	6,257	40,195	40,195	100.0%	0	0.0%
		Total	6,516	41,716	41,716	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	74,667	358,626	101,891	28.4%	256,735	71.6%
		Prevailing Flow	191,791	1,311,207	226,480	17.3%	1,084,727	82.7%
		Total	266,458	1,669,833	328,371	19.7%	1,341,462	80.3%
	Options	Counter Flow	172	13,006	0	0.0%	13,006	100.0%
		Prevailing Flow	28,074	878,996	42,924	4.9%	836,073	95.1%
		Total	28,246	892,002	42,924	4.8%	849,079	95.2%
	Total	Counter Flow	74,839	371,632	101,891	27.4%	269,741	72.6%
		Prevailing Flow	219,865	2,190,204	269,404	12.3%	1,920,800	87.7%
		Total	294,704	2,561,835	371,295	14.5%	2,190,541	85.5%
Sell offers	Obligations	Counter Flow	34,568	128,409	13,805	10.8%	114,604	89.2%
		Prevailing Flow	55,318	207,839	21,241	10.2%	186,598	89.8%
		Total	89,886	336,247	35,046	10.4%	301,202	89.6%
	Options	Counter Flow	5	100	0	0.0%	100	100.0%
		Prevailing Flow	2,090	19,951	229	1.1%	19,722	98.9%
		Total	2,095	20,051	229	1.1%	19,822	98.9%
	Total	Counter Flow	34,573	128,509	13,805	10.7%	114,704	89.3%
		Prevailing Flow	57,408	227,790	21,470	9.4%	206,320	90.6%
		Total	91,981	356,299	35,275	9.9%	321,024	90.1%

Table 12-12 shows the proportion of ARRs self scheduled as FTRs for the last four planning periods. The maximum possible level of self-scheduled FTRs includes all ARRs, including RTEP ARRs. Eligible participants self scheduled 41,716 MW (42.1 percent) of ARRs into FTRs for the 2012 to 2013 planning period, down from 46,017 MW (44.4 percent) in the previous planning period.

Table 12-12 Comparison of self-scheduled FTRs: Planning periods from 2008 to 2009 through 2012 to 2013

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2009/2010	68,589	109,612	62.6%
2010/2011	55,732	102,046	54.6%
2011/2012	46,017	103,735	44.4%
2012/2013	41,716	99,115	42.1%

Table 12-13 Monthly Balance of Planning Period FTR Auction market volume: January through December 2012

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-12	Obligations	Buy bids	185,712	1,024,729	146,344	14.3%	878,385	85.7%
		Sell offers	75,415	421,756	48,770	11.6%	372,986	88.4%
	Options	Buy bids	2,721	215,626	1,680	0.8%	213,946	99.2%
		Sell offers	5,615	45,756	10,572	23.1%	35,184	76.9%
Feb-12	Obligations	Buy bids	207,775	1,039,918	147,207	14.2%	892,711	85.8%
		Sell offers	80,631	375,855	47,609	12.7%	328,246	87.3%
	Options	Buy bids	2,247	194,423	2,620	1.3%	191,804	98.7%
		Sell offers	5,299	42,130	8,241	19.6%	33,889	80.4%
Mar-12	Obligations	Buy bids	197,115	893,900	156,694	17.5%	737,206	82.5%
		Sell offers	77,440	400,030	50,162	12.5%	349,868	87.5%
	Options	Buy bids	3,463	232,307	5,079	2.2%	227,228	97.8%
		Sell offers	5,869	60,228	11,952	19.8%	48,276	80.2%
Apr-12	Obligations	Buy bids	142,073	662,487	128,791	19.4%	533,695	80.6%
		Sell offers	55,915	306,492	49,050	16.0%	257,442	84.0%
	Options	Buy bids	4,259	133,298	2,427	1.8%	130,871	98.2%
		Sell offers	3,767	40,214	9,597	23.9%	30,617	76.1%
May-12	Obligations	Buy bids	89,626	464,275	93,721	20.2%	370,554	79.8%
		Sell offers	27,827	156,483	42,051	26.9%	114,432	73.1%
	Options	Buy bids	539	6,220	921	14.8%	5,299	85.2%
		Sell offers	2,017	18,909	10,402	55.0%	8,507	45.0%
Jun-12	Obligations	Buy bids	231,094	1,308,800	200,836	15.3%	1,107,963	84.7%
		Sell offers	88,406	418,825	33,562	8.0%	385,262	92.0%
	Options	Buy bids	20,190	1,314,332	8,527	0.6%	1,305,806	99.4%
		Sell offers	19,390	163,948	35,669	21.8%	128,279	78.2%
Jul-12	Obligations	Buy bids	268,379	1,355,612	244,325	18.0%	1,111,287	82.0%
		Sell offers	103,032	444,140	43,815	9.9%	400,325	90.1%
	Options	Buy bids	20,083	1,379,657	7,624	0.6%	1,372,033	99.4%
		Sell offers	15,896	113,139	25,438	22.5%	87,701	77.5%
Aug-12	Obligations	Buy bids	240,490	1,320,134	219,428	16.6%	1,100,706	83.4%
		Sell offers	108,381	395,062	49,382	12.5%	345,680	87.5%
	Options	Buy bids	4,582	98,115	7,004	7.1%	91,112	92.9%
		Sell offers	17,553	114,076	25,357	22.2%	88,719	77.8%
Sep-12	Obligations	Buy bids	232,215	1,308,752	206,467	15.8%	1,102,286	84.2%
		Sell offers	127,461	456,861	43,445	9.5%	413,416	90.5%
	Options	Buy bids	14,767	1,137,801	10,587	0.9%	1,127,214	99.1%
		Sell offers	17,728	111,945	27,256	24.3%	84,688	75.7%
Oct-12	Obligations	Buy bids	212,873	1,189,069	183,994	15.5%	1,005,075	84.5%
		Sell offers	131,361	431,358	47,798	11.1%	383,560	88.9%
	Options	Buy bids	5,672	121,791	5,639	4.6%	116,151	95.4%
		Sell offers	13,851	91,016	23,783	26.1%	67,233	73.9%
Nov-12	Obligations	Buy bids	184,712	984,123	147,854	15.0%	836,269	85.0%
		Sell offers	97,610	284,595	36,608	12.9%	247,987	87.1%
	Options	Buy bids	14,263	1,158,108	6,272	0.5%	1,151,836	99.5%
		Sell offers	12,791	91,762	19,025	20.7%	72,737	79.3%
Dec-12	Obligations	Buy bids	170,972	1,093,875	183,722	16.8%	910,153	83.2%
		Sell offers	105,736	374,995	49,505	13.2%	325,490	86.8%
	Options	Buy bids	13,703	1,136,516	5,159	0.5%	1,131,356	99.5%
		Sell offers	14,103	98,103	24,054	24.5%	74,050	75.5%
2011/2012*	Obligations	Buy bids	2,787,546	15,084,909	2,216,646	14.7%	12,868,263	85.3%
		Sell offers	1,078,612	5,164,979	551,669	10.7%	4,613,310	89.3%
	Options	Buy bids	40,237	2,549,347	58,829	2.3%	2,490,519	97.7%
		Sell offers	99,695	687,656	164,180	23.9%	523,476	76.1%
2012/2013**	Obligations	Buy bids	1,540,735	8,560,365	1,386,626	16.2%	7,173,739	83.8%
		Sell offers	761,987	2,805,836	304,115	10.8%	2,501,721	89.2%
	Options	Buy bids	93,260	6,346,319	50,812	0.8%	6,295,508	99.2%
		Sell offers	111,312	783,988	180,581	23.0%	603,407	77.0%

* Shows Twelve Months for 2011/2012; ** Shows seven months ended 31-Dec-12 for 2012/2013

Table 12-13 provides the Monthly Balance of Planning Period FTR Auction market volume for 2012, the entire 2011 to 2012 planning period and the first seven months of the 2012 to 2013 planning period. There were 8,560,365 MW of FTR buy bid obligations and 2,805,836 MW of FTR sell offer obligations for all bidding periods in the 2012 to 2013 planning period through December 31, 2012. The monthly balance of planning period auctions cleared 1,386,626 MW (16.2 percent) of FTR buy bid obligations and 304,115 MW (10.8 percent) of FTR sell off obligations.

Table 12-14 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): January through June 2012

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-12	Bid	649,775	210,717	168,284				211,578	1,240,355
	Cleared	110,546	15,316	8,624				13,537	148,024
Feb-12	Bid	651,268	240,292	189,159				153,622	1,234,341
	Cleared	103,278	20,608	15,634				10,307	149,827
Mar-12	Bid	570,266	266,873	208,586				80,482	1,126,207
	Cleared	117,447	22,710	16,217				5,400	161,773
Apr-12	Bid	579,513	216,271						795,784
	Cleared	115,408	15,810						131,218
May-12	Bid	470,495							470,495
	Cleared	94,642							94,642
Jun-12	Bid	708,790	372,480	348,955	92,103	365,680	369,416	365,707	2,623,132
	Cleared	104,967	20,127	16,731	9,850	22,471	17,552	17,664	209,363
Jul-12	Bid	810,399	393,948	356,419		397,111	396,290	381,102	2,735,269
	Cleared	130,965	26,218	17,256		25,812	27,939	23,759	251,949
Aug-12	Bid	650,279	166,379	162,525		121,561	163,558	153,946	1,418,249
	Cleared	130,706	20,892	20,608		11,719	22,169	20,337	226,432
Sep-12	Bid	794,152	384,866	356,543		120,840	400,055	390,097	2,446,553
	Cleared	120,426	26,470	19,959		8,747	21,376	20,076	217,053
Oct-12	Bid	603,893	208,370	131,916			187,027	179,654	1,310,859
	Cleared	121,842	23,661	9,175			17,652	17,304	189,633
Nov-12	Bid	716,796	346,772	339,248			362,368	377,047	2,142,231
	Cleared	96,262	12,862	9,548			14,916	20,539	154,126
Dec-12	Bid	792,466	360,631	357,417			336,770	383,106	2,230,391
	Cleared	127,590	16,119	15,003			10,255	19,913	188,881

There were 6,346,319 MW of FTR buy bid options and 783,988 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period through December 31, 2012. The monthly auctions cleared 50,812 MW (0.8 percent) of FTR buy bid options, an increase of 10.2 percent over the previous planning period, and 180,581 MW (23.0 percent) of FTR sell offers, an increase of 59.2 percent.

The Monthly Balance of Planning Period FTR Auctions for the full 12-months of the 2011 to 2012 planning period had a total demand of 17,646,257 MW for FTR buy bids, an increase of 23.4 percent over the previous planning period, and 5,852,635 MW of FTR sell offers, an increase of 45.7 percent over the previous planning period. The total cleared FTR volume for the 2011 to 2012 planning period was 2,275,474 MW (12.9 percent) for FTR buy bids and 715,849 MW (12.2 percent) for FTR sell offers. Of the cleared volume 2,216,646 MW (97.4 percent) were buy bid obligations and 551,669 MW (77.1 percent) were sell offer obligations.

In the Monthly Balance of Planning Period FTR Auctions for the 2011 to 2012 planning period, total participant FTR sell offers were 5,852,635 MW, up from 4,017,266 MW for the same period during the 2010 to 2011 planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2011 to 2012 planning period increased 23.4 percent from 14,291,535MW, during the same time period of the prior planning period, to 17,634,256 MW. For the 2011 to 2012 planning period, FTR auctions cleared 2,275,475 MW (12.9 percent) of FTR buy bids and 715,849 MW (12.2 percent) of sell offers.

Table 12-14 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume.

Figure 12-3 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through December 2012, 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 12-3 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through December 2012[17]

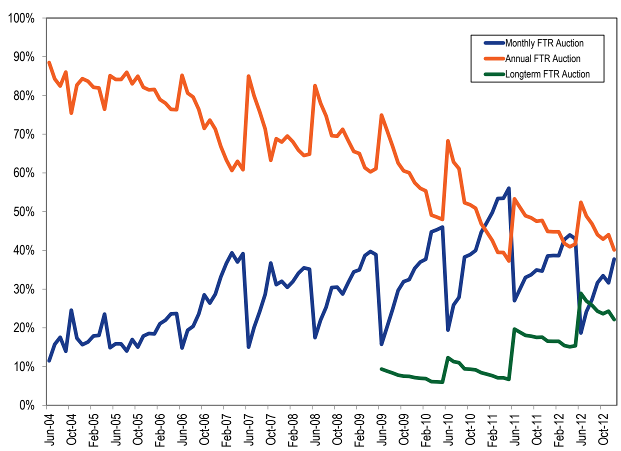


Table 12-15 provides the secondary bilateral FTR market volume for the entire 2011 to 2012 planning period and the four months of the 2012 to 2013 planning period.

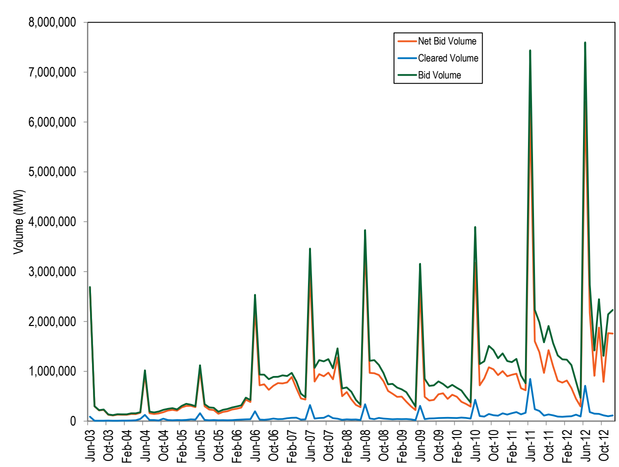
Table 12-15 Secondary bilateral FTR market volume: Planning periods 2011 to 2012 and 2012 to 2013[18]

Planning Period	Hedge Type	Class Type	Volume (MW)
2011/2012	Obligation	24-Hour	239
		On Peak	11,925
		Off Peak	4,268
		Total	16,431
	Option	24-Hour	0
		On Peak	8,965
		Off Peak	6,330
		Total	15,296
2012/2013*	Obligation	24-Hour	90
		On Peak	48
		Off Peak	0
		Total	137
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0

* Shows seven months ended 31-Dec-2012

Figure 12-4 shows the FTR bid, cleared and net bid volume from June 2003 through December 2012 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.

Figure 12-4 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2012



17 Figure 12-3 does not include volume from FTRs directly allocated to either DEOK or ATSI zones as part of their integration for the 2011 to 2012 or 2012 to 2013 planning periods.

18 The 2012 to 2013 planning period covers bilateral FTRs that are effective for any time between June 1, 2012 through December 31, 2012, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Price

Table 12-16 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2013 to 2016 Long Term FTR Auction. Only FTR obligation products are available in the Long Term FTR Auctions. In this auction, weighted-average buy bid FTR prices were $0.05 per MW, the same as the 2012 to 2015 Long Term FTR Auction prices, while weighted-average sell offer FTR prices were $0.14 per MW, down $0.10 per MW from the previous Long Term FTR Auction.

Table 12-16 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): Planning periods 2013 to 2016

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($0.76)	($0.36)	($0.22)	($0.30)
		Year 2	($0.74)	($0.32)	($0.20)	($0.26)
		Year 3	($0.86)	($0.25)	($0.15)	($0.21)
		Year All	NA	($0.05)	($0.03)	($0.04)
		Total	($0.78)	($0.31)	($0.19)	($0.25)
	Prevailing Flow	Year 1	$1.56	$0.39	$0.26	$0.36
		Year 2	$1.06	$0.32	$0.21	$0.28
		Year 3	$1.14	$0.27	$0.16	$0.23
		Year All	NA	$0.12	$0.13	$0.13
		Total	$1.32	$0.33	$0.21	$0.29
	Total		$0.36	$0.06	$0.02	$0.05
Sell offers	Counter Flow	Year 1	($0.76)	($0.17)	($0.08)	($0.13)
		Year 2	NA	($0.11)	($0.04)	($0.06)
		Year 3	NA	($0.25)	($0.16)	($0.20)
		Year All	NA	NA	NA	NA
		Total	($0.76)	($0.15)	($0.07)	($0.10)
	Prevailing Flow	Year 1	$0.72	$0.42	$0.22	$0.33
		Year 2	$0.86	$0.29	$0.14	$0.22
		Year 3	NA	$0.32	$0.19	$0.27
		Year All	NA	NA	NA	NA
		Total	$0.78	$0.37	$0.19	$0.28
	Total		($0.17)	$0.22	$0.07	$0.14

Figure 12-5 shows the cleared buy bid price frequency for the 2013 to 2016 Long Term FTR Auction and that 95.9 percent of Long Term FTRs were purchased for less than $1 per MW. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs). The majority of the cleared bids for the 2013 to 2016 Long Term FTR Auction fall into the $0 to $2 range.

Figure 12-5 Long Term FTR Auction clearing price per MW frequency: Planning periods 2013 to 2016

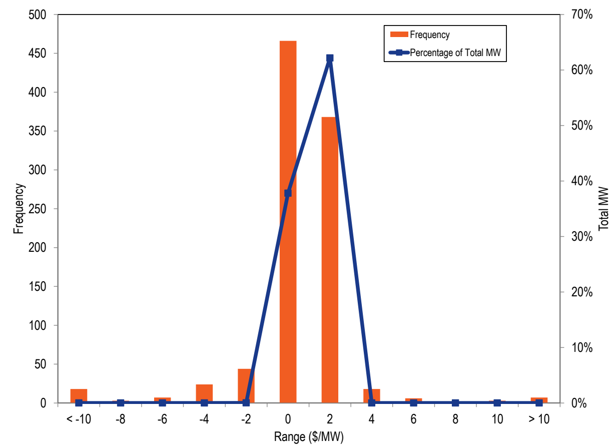


Table 12-17 shows the weighted-average cleared buy-bid prices by trade type, hedge type, FTR direction and class type for the Annual FTR Auction for the 2012 to 2013 planning period. For the 2012 to 2013 planning period the weighted-average buy bid FTR price was $0.23 per MW, up from $0.16 per MW in the 2011 to 2012 planning period. Buy bid obligation prices were $0.26 per MW, a $0.15 per MW decrease, and buy bid option prices were $0.23 per MW, a $0.07 per MW increase over the previous planning period. Weighted-average buy bid FTR obligation prices for counter flow FTRs were -$0.29 per MW, a $0.18 per MW increase over the previous planning period.

Self-scheduled FTRs are price takers and do not enter a bid price into the Annual FTR Auction. The prices reported here reflect the prices set in the auction on the FTR paths that were self-scheduled. On average in the 2012 to 2013 Annual FTR Auction, self-scheduled FTRs, priced at $0.65 per MW, were priced $0.39 per MW higher than buy bid obligation FTRs, but a $0.51 per MW decrease over the 2011 to 2012 planning period. Self-scheduled counter flows FTRs were priced only $0.01 per MW lower than buy bid obligation counter flow FTRs and self-scheduled prevailing flow FTRs were priced $0.14 per MW higher than buy bid obligations. In the 2011 to 2012 planning period, these differences were $0.36 per MW and $0.41 per MW.

Table 12-17 Annual FTR Auction weighted-average cleared prices (Dollars per MW): Planning period 2012 to 2013[19]

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.19)	($0.40)	($0.22)	($0.29)
		Prevailing Flow	$0.53	$0.66	$0.43	$0.55
		Total	$0.40	$0.31	$0.18	$0.26
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.74	$0.31	$0.15	$0.23
		Total	$0.74	$0.31	$0.15	$0.23
Self-scheduled bids	Obligations	Counter Flow	($0.30)	NA	NA	($0.30)
		Prevailing Flow	$0.69	NA	NA	$0.69
		Total	$0.65	NA	NA	$0.65
Buy and self-scheduled bids	Obligations	Counter Flow	($0.22)	($0.40)	($0.22)	($0.29)
		Prevailing Flow	$0.65	$0.66	$0.43	$0.59
		Total	$0.58	$0.31	$0.18	$0.34
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.74	$0.31	$0.15	$0.23
		Total	$0.74	$0.31	$0.15	$0.23
Sell offers	Obligations	Counter Flow	($0.53)	($0.31)	($0.20)	($0.26)
		Prevailing Flow	$0.28	$0.40	$0.22	$0.31
		Total	$0.08	$0.24	$0.08	$0.15
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.37	$0.17	$0.31
		Total	$0.00	$0.37	$0.17	$0.31

Figure 12-6 shows the weighted-average cleared buy-bid price frequency for the 2012 to 2013 Annual FTR Auction and that 90.4 percent of Annual FTRs were purchased for less than $1 per MW. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs). The 2012 to 2013 planning period FTR obligation price frequency for cleared buy bids shows that 89.5 percent of FTR buy bid obligations and 96.5 percent of FTR buy bid options were purchased for less than $1 per MW.

Figure 12-6 Annual FTR Auction clearing price per MW: Planning period 2012 to 2013

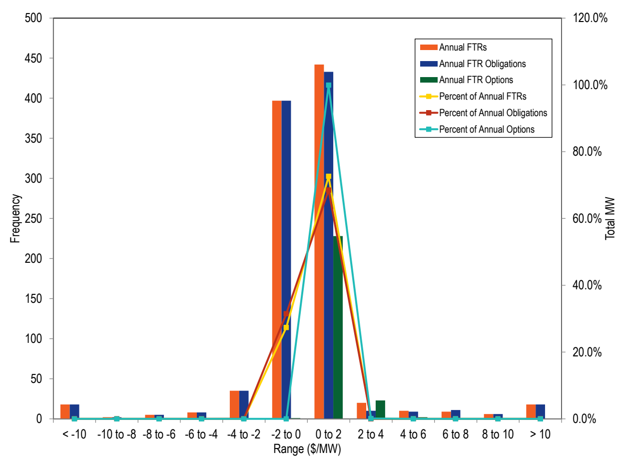


Table 12-18 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2012 through December 2012. For example, for the June 2012 Monthly Balance of Planning Period FTR Auction, the current month column is June, the second month column is July and the third month column is August. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the June 2012 Monthly Balance of Planning Period FTR Auction.

19 Price data for the 2012 to 2013 Annual FTR Auction does not include FTRs directly allocated within the ATSI and DEOK Control Zones.

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2012 to 2013 planning period was $0.12 per MW compared to $0.10 per MW for the same time frame in the 2011 to 2012 planning period. The cleared weighted-average price paid for 2012 was $0.11, up from $0.10 for 2011.

Table 12-18 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through December 2012

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-12	$0.10	$0.14	$0.04				$0.13	$0.11
Feb-12	$0.10	$0.09	$0.11				$0.16	$0.11
Mar-12	$0.06	$0.13	$0.11				$0.01	$0.07
Apr-12	$0.08	$0.15						$0.08
May-12	$0.11							$0.11
Jun-12	$0.11	$0.20	$0.16	$0.30	$0.10	$0.17	$0.10	$0.14
Jul-12	$0.09	$0.11	$0.03		$0.09	$0.12	$0.08	$0.09
Aug-12	$0.10	$0.09	$0.09		$0.08	$0.19	$0.10	$0.11
Sep-12	$0.08	$0.15	$0.11		$0.06	$0.18	$0.13	$0.11
Oct-12	$0.09	$0.14	$0.04			$0.18	$0.11	$0.11
Nov-12	$0.09	$0.15	$0.15			$0.26	$0.14	$0.14
Dec-12	$0.09	$0.17	$0.16			$0.38	$0.13	$0.15

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 receives and the FTR credits are the cost to the FTR holder. The cost of self-scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction, but ARR holders receive offsetting ARR credits that equal the purchase price of the FTRs. Table 12-19 lists FTR profits by organization type and FTR direction for the period from January through December, 2012. FTR profits are the sum of the daily FTR credits, including 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 $-7.6 million in profits for physical entities, of which $151.3 million was from self-scheduled FTRs, and $78.8 million for financial entities.

Table 12-19 FTR profits by organization type and FTR direction: January through December 2012

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	($217,458,432)	$148,975,735	$58,491,863	$2,356,793	($7,634,041)
Financial	($75,529,744)	NA	$154,292,667	NA	$78,762,923
Total	($292,988,176)	$148,975,735	$212,784,530	$2,356,793	$71,128,882

Table 12-20 lists the monthly FTR profits in 2012 by organization type.

Table 12-20 Monthly FTR profits by organization type: January through December 2012

	Organization Type			
Month	Physical	Self Scheduled FTRs	Financial	Total
Jan	($21,202,380)	$14,779,795	$3,981,524	($2,441,061)
Feb	($23,137,563)	$13,247,875	$7,491,849	($2,397,839)
Mar	($24,189,367)	$12,778,994	$4,873,661	($6,536,712)
Apr	($17,314,923)	$11,004,118	$11,848,177	$5,537,372
May	($22,911,625)	$11,306,839	$13,000,958	$1,396,172
Jun	($220,426)	$839,141	$173,901	$792,616
Jul	($1,394,243)	$18,497,143	$7,160,965	$24,263,866
Aug	($14,487,392)	$16,807,177	$3,281,077	$5,600,862
Sep	($5,106,566)	$16,795,363	$13,936,777	$25,625,574
Oct	($11,489,644)	$12,386,162	$6,364,575	$7,261,092
Nov	($5,953,176)	$11,979,982	$4,521,332	$10,548,138
Dec	($11,559,264)	$10,909,938	$2,128,126	$1,478,800
Total	($158,966,569)	$151,332,528	$78,762,923	$71,128,882

Revenue

Long Term FTR Auction Revenue

Table 12-21 shows the Long Term FTR Auction revenue data by trade type, FTR direction, period type and class type. The 2013 to 2016 Long Term FTR Auction netted $28.6 million in revenue, $8.1 million more than the previous Long Term FTR Auction. Buyers paid $62.7 million and sellers received $34.1 million, up $8.3 million and $0.3 million over the previous Long Term FTR Auction.

For the 2013 to 2016 Long Term FTR Auction, the counter flow FTRs netted -$138.5 million in revenue, down $21.0 million, while prevailing flow FTRs netted $167.1 million in revenue, up $29.1 million from the previous Long Term FTR Auction.

Figure 12-7 summarizes total revenue associated with all FTRs, regardless of source, to FTR sinks that produced the largest positive and negative revenue from the 2013 to 2016 Long Term FTR Auction.[20] The top 10 positive revenue producing FTR sources accounted for $69.6 million of the total revenue of $28.5 million paid in the auction, they also comprised 7.1 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$41.3 million of revenue and constituted 4.1 percent of all FTRs bought in the auction.

Table 12-21 Long Term FTR Auction revenue: Planning periods 2013 to 2016

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($5,706,284)	($35,831,285)	($28,995,134)	($70,532,704)
		Year 2	($2,349,323)	($20,540,182)	($18,949,698)	($41,839,203)
		Year 3	($2,364,201)	($18,374,522)	($14,391,797)	($35,130,521)
		Year All	$0	($377,197)	($505,873)	($883,070)
		Total	($10,419,808)	($75,123,187)	($62,842,503)	($148,385,497)
	Prevailing Flow	Year 1	$12,341,292	$53,723,120	$35,976,381	$102,040,793
		Year 2	$5,305,552	$30,670,166	$23,466,587	$59,442,305
		Year 3	$3,458,467	$27,018,434	$18,074,490	$48,551,391
		Year All	$0	$319,599	$702,726	$1,022,325
		Total	$21,105,311	$111,731,319	$78,220,183	$211,056,813
	Total		$10,685,504	$36,608,132	$15,377,680	$62,671,316
Sell offers	Counter Flow	Year 1	($935,293)	($3,249,168)	($2,567,347)	($6,751,808)
		Year 2	$0	($1,291,866)	($1,208,534)	($2,500,400)
		Year 3	$0	($333,864)	($270,553)	($604,418)
		Year All	NA	NA	NA	NA
		Total	($935,293)	($4,874,898)	($4,046,435)	($9,856,626)
	Prevailing Flow	Year 1	$329,797	$19,720,323	$9,307,306	$29,357,426
		Year 2	$264,183	$8,565,500	$4,144,029	$12,973,711
		Year 3	$0	$1,112,660	$479,173	$1,591,833
		Year All	NA	NA	NA	NA
		Total	$593,980	$29,398,482	$13,930,508	$43,922,970
	Total		($341,313)	$24,523,584	$9,884,074	$34,066,345
Total			$11,026,817	$12,084,548	$5,493,606	$28,604,971

20 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

Figure 12-7 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2013 to 2016

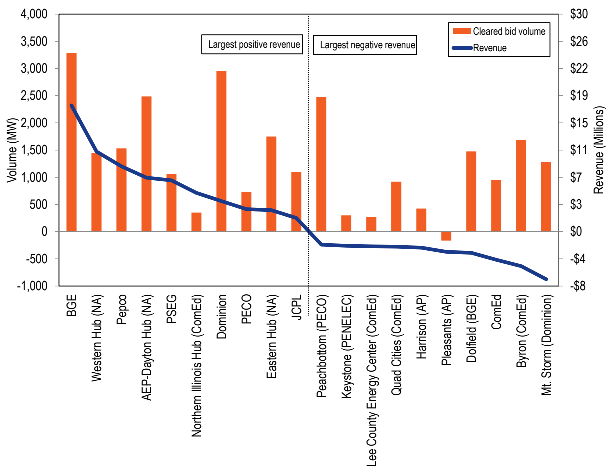


Figure 12-8 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2013 to 2016[23]

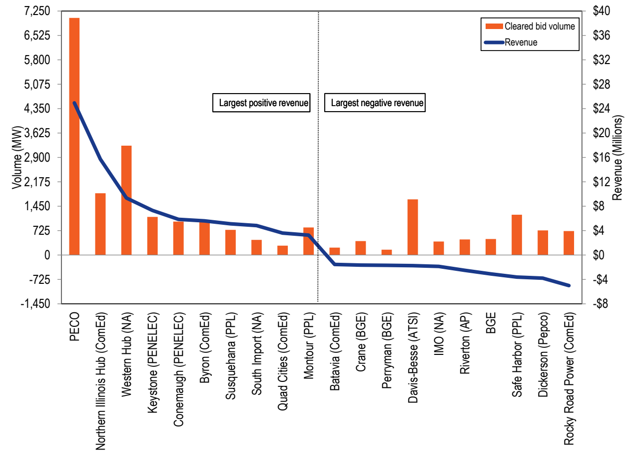


Figure 12-8 summarizes total revenue associated with all FTRs, regardless of sink, to FTR sources that produced the largest positive and negative revenue from the 2013 to 2016 Long Term FTR Auction.[21] The top 10 positive revenue producing FTR sources accounted for $85.6 million of the total revenue of $28.5 million paid in the auction, they also comprised 7.4 percent of all FTRs bought in the auction.[22] The top 10 negative revenue producing FTR sources accounted for -$38.7 million of revenue and constituted 2.7 percent of all FTRs bought in the auction.

Annual FTR Auction Revenue

Table 12-22 shows the Annual FTR Auction revenue data by trade type, hedge type, FTR direction and class type. The Annual FTR Auction for the 2012 to 2013 planning period generated $602.9 million, down 41.4 percent from $1,029.6 million in the 2011 to 2012 planning period. FTR buyers paid $627.3 million, down $440.9 million, and sellers received $24.4 million, down $14.2 million from the previous Annual FTR Auction.

For the 2012 to 2013 planning period, counter flow FTRs in the Annual FTR Auction netted -$123.1 million, down $59.2 million from the previous Annual Auction with buyers receiving $134.9 million and sellers paying $11.7 million. In the Annual FTR Auction prevailing flow buyers paid $762.2 million and sellers received $36.2 million. Counter flow FTR buyers are paid to take FTRs, so revenues are negative for buyers and positive for sellers.

21 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

22 The total positive revenue producing FTR sources was $67.3 million and the total negative revenue producing FTR sinks was -$38.7 million. The overall revenue paid in the auction was $28.5 million.

23 For Figure 12-7 through Figure 12-14, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Table 12-22 Annual FTR Auction revenue: Planning period 2012 to 2013

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($5,370,727)	($73,472,255)	($52,027,158)	($130,870,140)
		Prevailing Flow	$65,363,056	$251,064,599	$160,673,442	$477,101,097
		Total	$59,992,329	$177,592,343	$108,646,285	$346,230,957
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,286,535	$25,658,484	$15,913,602	$42,858,621
		Total	$1,286,535	$25,658,484	$15,913,602	$42,858,621
	Total	Counter Flow	($5,370,727)	($73,472,255)	($52,027,158)	($130,870,140)
		Prevailing Flow	$66,649,591	$276,723,083	$176,587,045	$519,959,718
		Total	$61,278,864	$203,250,827	$124,559,887	$389,089,578
Self-scheduled bids	Obligations	Counter Flow	($4,001,799)	NA	NA	($4,001,799)
		Prevailing Flow	$242,193,633	NA	NA	$242,193,633
		Total	$238,191,834	NA	NA	$238,191,834
Buy and self-scheduled bids	Obligations	Counter Flow	($9,372,526)	($73,472,255)	($52,027,158)	($134,871,939)
		Prevailing Flow	$307,556,690	$251,064,599	$160,673,442	$719,294,730
		Total	$298,184,163	$177,592,343	$108,646,285	$584,422,791
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,286,535	$25,658,484	$15,913,602	$42,858,621
		Total	$1,286,535	$25,658,484	$15,913,602	$42,858,621
	Total	Counter Flow	($9,372,526)	($73,472,255)	($52,027,158)	($134,871,939)
		Prevailing Flow	$308,843,224	$276,723,083	$176,587,045	$762,153,351
		Total	$299,470,698	$203,250,827	$124,559,887	$627,281,412
Sell offers	Obligations	Counter Flow	($1,614,398)	($5,346,361)	($4,788,710)	($11,749,469)
		Prevailing Flow	$2,650,769	$22,966,327	$10,249,618	$35,866,714
		Total	$1,036,371	$17,619,966	$5,460,908	$24,117,244
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$254,602	$47,689	$302,291
		Total	$0	$254,602	$47,689	$302,291
	Total	Counter Flow	($1,614,398)	($5,346,361)	($4,788,710)	($11,749,469)
		Prevailing Flow	$2,650,769	$23,220,929	$10,297,306	$36,169,005
		Total	$1,036,371	$17,874,568	$5,508,597	$24,419,536
Total			$298,434,327	$185,376,259	$119,051,290	$602,861,876

Figure 12-9 summarizes total revenue associated with all FTRs, regardless of sink, to FTR sources that produced the largest positive and negative revenue from the 2012 to 2013 Annual FTR Auction.[24] The top 10 positive revenue producing FTR sources accounted for $871.5 million (84.6 percent) of the total revenue of $1,029.7 million paid in the auction, they also comprised 27.3 percent of all FTRs bought in the auction.[25] The top 10 negative revenue producing FTR sources accounted for -$71.2 million of revenue and constituted 6.9 percent of all FTRs bought in the auction.

Figure 12-9 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2012 to 2013

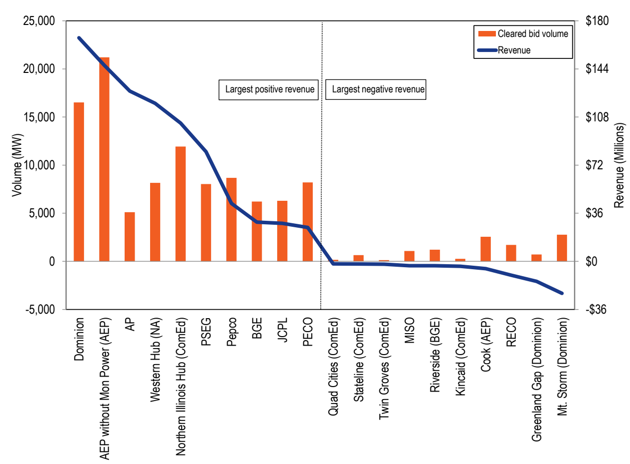


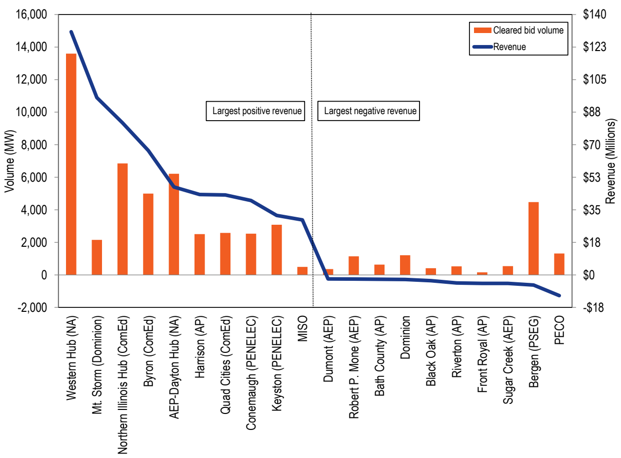
Figure 12-10 summarizes total revenue associated with all FTRs, regardless of source, to FTR sinks that produced the largest positive and negative revenue from the 2013

24 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

25 The total positive revenue producing FTR sources was $67.3 million and the total negative revenue producing FTR sinks was -$38.7 million. The overall revenue paid in the auction was $28.5 million.

to 2016 Annual FTR Auction.[26] The top 10 positive revenue producing FTR sources accounted for $609.8 million of the total revenue of $1,031.0 million paid in the auction, they also comprised 12.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$42.3 million of revenue and constituted 2.9 percent of all FTRs bought in the auction.

Figure 12-10 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2012 to 2013

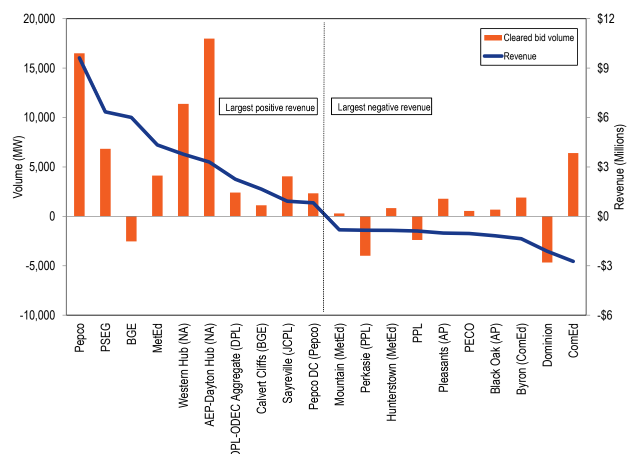


Monthly Balance of Planning Period FTR Auction Revenue

Table 12-23 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, type and class type for January through December 2012. The Monthly Balance of Planning Period FTR Auction netted $17.3 million in revenue, with buyers paying $95.2 million and sellers receiving $77.9 million. For the entire 2011 to 2012 planning period, the Monthly Balance of Planning Period FTR Auctions netted $26.3 million in revenue with buyers paying $132.6 million and sellers receiving $106.4 million.

Figure 12-11 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 2012 to 2013 planning period. The top 10 positive revenue producing FTR sources accounted for $39.0 million of the total revenue of $17.3 million paid in the auction, they also comprised 6.7 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$12.9 million of revenue and constituted 0.1 percent of all FTRs bought in the auction.

Figure 12-11 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2012 to 2013



26 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

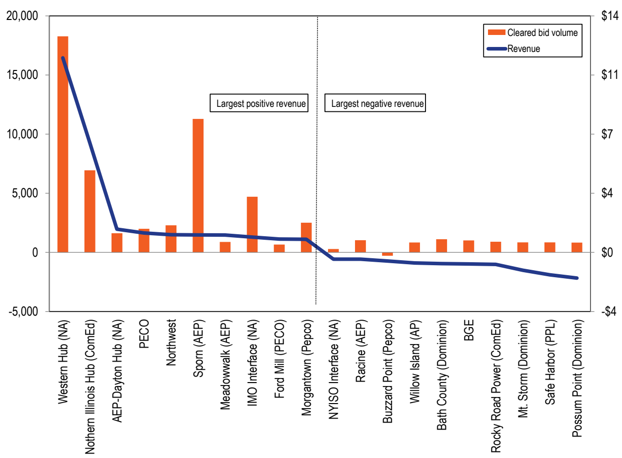
Table 12-23 Monthly Balance of Planning Period FTR Auction revenue: January through December 2012

Monthly			Class Type			
Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-12	Obligations	Buy bids	$524,730	$3,220,163	$2,694,130	$6,439,023
		Sell offers	$273,645	$2,111,566	$1,753,975	$4,139,186
	Options	Buy bids	$47,640	$250,066	$185,282	$482,989
		Sell offers	$3,520	$1,158,143	$803,885	$1,965,548
Feb-12	Obligations	Buy bids	$738,466	$3,603,048	$2,051,190	$6,392,705
		Sell offers	$157,900	$3,038,310	$1,577,337	$4,773,546
	Options	Buy bids	$0	$289,791	$229,111	$518,902
		Sell offers	$0	$648,876	$439,093	$1,087,969
Mar-12	Obligations	Buy bids	$52,294	$2,878,603	$1,411,063	$4,341,960
		Sell offers	$205,654	$1,869,094	$670,898	$2,745,647
	Options	Buy bids	$9,004	$170,196	$109,643	$288,843
		Sell offers	$0	$613,978	$496,981	$1,110,960
Apr-12	Obligations	Buy bids	($103,515)	$2,497,186	$1,518,273	$3,911,943
		Sell offers	$261,819	$1,380,449	$742,304	$2,384,572
	Options	Buy bids	$0	$66,944	$50,134	$117,078
		Sell offers	$0	$455,585	$380,110	$835,695
May-12	Obligations	Buy bids	$331,445	$1,959,349	$1,414,983	$3,705,777
		Sell offers	$20,537	$1,196,092	$767,455	$1,984,084
	Options	Buy bids	$0	$22,067	$12,390	$34,458
		Sell offers	$4,435	$569,872	$486,239	$1,060,545
Jun-12	Obligations	Buy bids	$1,675,452	$10,781,405	$4,151,710	$16,608,567
		Sell offers	$374,681	$6,390,257	$1,919,494	$8,684,433
	Options	Buy bids	$64,800	$685,972	$578,673	$1,329,445
		Sell offers	$0	$3,780,497	$2,069,955	$5,850,452
Jul-12	Obligations	Buy bids	($859,311)	$9,916,659	$3,550,156	$12,607,505
		Sell offers	($849,209)	$6,099,746	$1,367,013	$6,617,550
	Options	Buy bids	$0	$736,304	$502,081	$1,238,385
		Sell offers	$0	$2,857,593	$1,792,063	$4,649,656
Aug-12	Obligations	Buy bids	$48,011	$8,111,495	$4,740,753	$12,900,258
		Sell offers	$32,573	$4,002,172	$1,840,346	$5,875,091
	Options	Buy bids	$965	$752,557	$296,514	$1,050,035
		Sell offers	$5,087	$2,340,565	$1,958,938	$4,304,590
Sep-12	Obligations	Buy bids	($608,953)	$8,762,531	$4,088,277	$12,241,856
		Sell offers	$436,202	$4,077,427	$1,414,673	$5,928,301
	Options	Buy bids	$1,436	$650,310	$336,001	$987,746
		Sell offers	$0	$3,190,050	$1,947,586	$5,137,636
Oct-12	Obligations	Buy bids	$170,435	$6,714,889	$3,496,860	$10,382,184
		Sell offers	$187,897	$3,665,626	$1,540,352	$5,393,876
	Options	Buy bids	$0	$238,541	$212,202	$450,742
		Sell offers	$0	$2,118,759	$1,451,870	$3,570,629
Nov-12	Obligations	Buy bids	($555,956)	$7,052,316	$4,982,409	$11,478,770
		Sell offers	$2,932,597	$2,214,344	$1,513,456	$6,660,397
	Options	Buy bids	$16,567	$197,934	$147,344	$361,845
		Sell offers	$278,683	$1,506,825	$1,605,097	$3,390,604
Dec-12	Obligations	Buy bids	($206,407)	$6,937,534	$6,297,431	$13,028,558
		Sell offers	$420,872	$4,227,841	$3,644,941	$8,293,654
	Options	Buy bids	$0	$301,266	$194,916	$496,182
		Sell offers	$29,550	$1,653,241	$1,821,150	$3,503,940
2011/2012*	Obligations	Buy bids	$11,022,879	$70,675,860	$43,198,742	$124,897,481
		Sell offers	$4,694,451	$44,380,545	$26,582,133	$75,657,129
	Options	Buy bids	$117,492	$4,428,304	$3,191,765	$7,737,562
		Sell offers	$14,172	$18,614,021	$12,092,649	$30,720,842
	Total		$6,431,748	$12,109,598	$7,715,726	$26,257,072
2012/2013**	Obligations	Buy bids	($336,729)	$58,276,830	$31,307,596	$89,247,698
		Sell offers	$3,535,614	$30,677,412	$13,240,275	$47,453,302
	Options	Buy bids	$83,767	$3,562,883	$2,267,731	$5,914,381
		Sell offers	$313,319	$17,447,531	$12,646,657	$30,407,507
	Total		($4,101,895)	$13,714,770	$7,688,395	$17,301,270

* Shows Twelve Months for 2011/2012; ** Shows seven months ended 31-Dec-2012 for 2012/2013

Figure 12-12 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 2012 to 2013 planning period. The top 10 positive revenue producing FTR sources accounted for $26.1 million of the total revenue of $25.9 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 -$7.9 million of revenue and constituted 0.5 percent of all FTRs bought in the auction.

Figure 12-12 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2012 to 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 2012 to 2013 planning period through December 31, 2012. Figure 12-13 shows the ten largest positive and negative FTR target allocations, summed by sink, for the 2012 to 2013 planning period. The top 10 sinks that produced financial benefit accounted for 21.7 percent of total positive target allocations during the first seven months of the 2012 to 2013 planning period with the Northern Illinois Hub accounting for 5.5 percent of all positive target allocations. The top 10 sinks that created liability accounted for 10.2 percent of total negative target allocations with Quad Cities 2 accounting for 2.0 percent of all negative target allocations.

Figure 12-13 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2012 to 2013

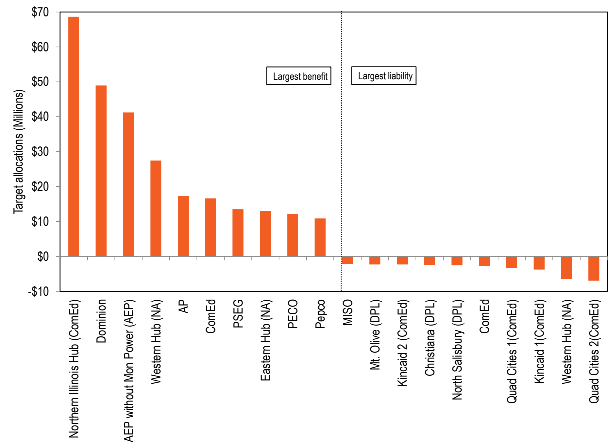
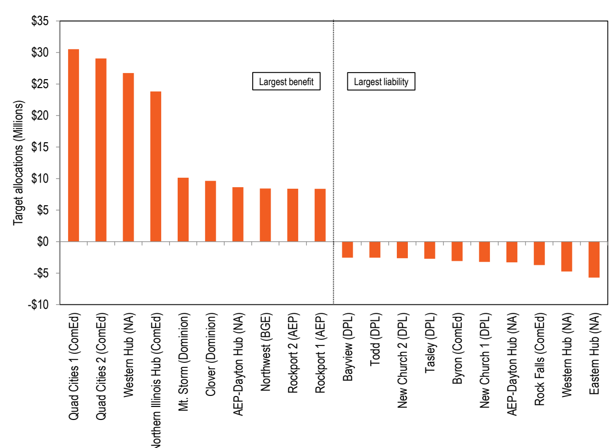


Figure 12-14 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2012 to 2013 planning period. The top 10 sources with a positive target allocation accounted for 13.2 percent of total positive target allocations with Quad Cities 1 accounting for 2.5 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 10.0 percent of all negative target allocations, with the Eastern Hub accounting for 1.7 percent.

Figure 12-14 Ten largest positive and negative FTR target allocations summed by source: Planning period 2012 to 2013



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load 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.[27] That 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 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 net negative congestion.[28] 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 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 12-24 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.[29] 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 a payment of $0.8 million in congestion charges to Con Edison in the 2011 to 2012 planning period.[30,31]

Congestion charges were made to the Day Ahead Operating Reserves in October 2012. These charges may be necessary if the hourly congestion revenues are negative at the end of the month. If this happens, charges are made and allocated as additional Day-Ahead Operating Reserves charges during the month. This means that within an hour, the congestion dollars collected from load were less than the congestion dollars paid to generation. This is accounted for as a charge, which is allocated to Day-Ahead Operating Reserves. This type of adjustment is infrequent, occurring only three times in the 2010 to 2011 planning period.

27 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."

28 Hourly congestion revenues may be negative.

29 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)

30 111 FERC ¶ 61,228 (2005).

31 See the *2010 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 D-2, "Con Edison and PSE&G wheel settlements data: Calendar year 2010."

FTRs were paid at 74.8 percent of the target allocation level for the first seven months of the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $335.1 million of FTR revenues during the first seven months of the 2012 to 2013 planning period, and $569.1 million during the first seven months of the 2011 to 2012 planning period, a 41.1 percent decrease. For the first seven months of the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were the Northern Illinois Hub and Quad Cities 1. Similarly, the top sink and top source with the largest negative FTR target allocations were Quad Cities 2 and the Eastern Hub.

Table 12-24 presents the PJM FTR revenue detail for the 2011 to 2012 planning period and the first seven months of the 2012 to 2013 planning period.

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and equal the revenue required to compensate FTR holders fully 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 12-25 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 12-25 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 12-24 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013 through December 31, 2012

Accounting Element	2011/2012	2012/2013**
ARR information		
ARR target allocations	$982.9	$343.8
FTR auction revenue	$1,091.8	$379.4
ARR excess	$108.9	$35.6
FTR targets		
FTR target allocations	$992.8	$442.6
Adjustments:		
Adjustments to FTR target allocations	($1.1)	($0.6)
Total FTR targets	$991.7	$442.0
FTR revenues		
ARR excess	$108.9	$35.6
Competing uses	$0.1	$0.1
Congestion		
Net Negative Congestion (enter as negative)	($64.5)	($47.1)
Hourly congestion revenue	$835.5	$371.2
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($79.6)	($24.7)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	(0.2)	$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	($0.8)	($0.0)
Total FTR revenues	$799.4	$335.1
Excess revenues distributed to other months	$0.0	$0.0
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.6
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	$799.4	$335.7
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$799.6	$335.7
Remaining deficiency	$192.3	$106.3

** Shows seven month ended 31-Dec-12

Table 12-25 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 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-11	$134.6	$154.6	86.9%	$134.6	87.1%	($20.0)
Jul-11	$178.2	$181.4	97.8%	$178.2	98.3%	($3.1)
Aug-11	$70.6	$73.4	96.2%	$70.6	96.2%	($2.8)
Sep-11	$69.4	$88.3	78.6%	$69.4	78.7%	($18.8)
Oct-11	$37.5	$52.3	73.0%	$37.5	71.7%	($14.8)
Nov-11	$32.8	$57.1	57.4%	$32.8	57.4%	($24.4)
Dec-11	$46.4	$64.8	71.6%	$46.4	71.6%	($18.4)
Jan-12	$49.4	$61.8	79.8%	$49.4	80.0%	($12.4)
Feb-12	$38.4	$57.4	66.8%	$38.4	66.8%	($19.0)
Mar-12	$48.3	$57.8	84.2%	$48.3	83.6%	($9.5)
Apr-12	$40.6	$73.6	55.3%	$40.6	55.2%	($32.9)
May-12	$53.1	$69.3	76.7%	$53.1	76.6%	($16.2)
Summary for Planning Period 2011 to 2012						
Total	$799.4	$991.7		$799.4	80.6%	($192.3)
Jun-12	$58.5	$62.9	92.9%	$58.5	92.9%	($4.5)
Jul-12	$71.3	$80.1	88.9%	$71.3	88.9%	($8.9)
Aug-12	$54.1	$55.6	97.1%	$54.1	97.3%	($1.5)
Sep-12	$38.7	$82.8	46.7%	$38.7	46.8%	($44.1)
Oct-12	$24.3	$58.2	41.8%	$24.9	42.7%	$33.3
Nov-12	$52.0	$55.5	93.8%	$52.0	93.8%	$3.4
Dec-12	$36.3	$47.2	76.9%	$36.3	76.9%	$10.9
Summary for Planning Period 2012 to 2013						
Total	$335.1	$442.4		$335.7	75.9%	($106.6)

Figure 12-15 shows the original FTR payout ratio with adjustments by month, excluding excess revenue distribution, for January 2004 through December 2012. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 12-15 also shows the payout ratio after distributing excess revenue across months within the planning period. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. 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 12-15 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 through December 2012

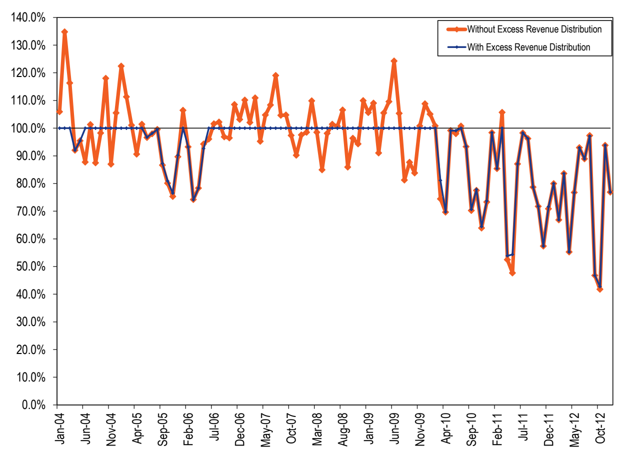


Table 12-26 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward.

Table 12-26 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*	74.8%

*2012/2013 Through 31-Dec-12

Revenue Adequacy Issues and Solutions

Reported Payout Ratio

The payout ratios shown above in Table 12-26 reflect the reported payout ratios for 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. But this does not correctly measure the payout ratio actually received by positive target allocation FTR holders. The payout ratio is intended to measure the proportion of the target allocation received by the holders of FTRs with positive target allocations in an hour. In fact, the actual 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.[32] The actual 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 is greater than reported by PJM.

Table 12-27 shows the reported and actual payout ratio for each month and the calendar year 2012. In September the reported payout ratio is 8.8 percentage points below the actual payout ratio. For 2012 the reported payout ratio is 3.4 percentage points below the actual payout ratio. For 2012 the reported payout ratio is 73.5 percent while the correctly calculated payout ratio is 76.9 percent.

Table 12-27 Reported and Actual Payout Ratios for 2012

	Reported Payout Ratio	Actual Payout Ratio
Jan-12	80.1%	82.3%
Feb-12	66.9%	71.2%
Mar-12	83.6%	86.7%
Apr-12	55.2%	62.7%
May-12	76.7%	79.6%
Jun-12	92.9%	93.6%
Jul-12	88.9%	90.0%
Aug-12	97.3%	97.5%
Sep-12	46.8%	55.6%
Oct-12	41.8%	50.2%
Nov-12	87.2%	88.5%
Dec-12	72.2%	74.6%
Total	73.5%	76.9%

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

32 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012), p. 50

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.

Table 12-28 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 12-28 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)		$115.00	$45.00	$45.00	

Table 12-29 shows the total value in 2012 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 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 in 2012 would have been 88.1 percent instead of the reported 73.5 percent.

Table 12-29 Monthly positive and negative target allocations and payout ratios with and without hourly netting in 2012

	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-12	$69,520,143	($7,730,433)	$126,702,422	($64,766,863)	$49,465,924	80.1%	90.2%
Feb-12	$66,139,499	($8,722,011)	$124,792,575	($67,369,848)	$38,390,571	66.9%	84.7%
Mar-12	$71,521,584	($13,706,751)	$147,644,281	($89,829,450)	$48,331,587	83.6%	93.6%
Apr-12	$88,301,660	($14,712,532)	$190,422,018	($116,820,311)	$40,645,388	55.2%	82.7%
May-12	$79,061,876	($9,760,027)	$177,551,934	($108,239,496)	$53,188,585	76.7%	90.9%
Jun-12	$69,557,299	($6,623,560)	$121,217,938	($58,280,956)	$58,463,402	92.9%	96.3%
Jul-12	$89,179,225	($9,034,200)	$173,602,611	($93,421,963)	$71,254,665	88.9%	94.9%
Aug-12	$60,694,118	($5,115,960)	$111,642,193	($55,976,928)	$54,064,320	97.3%	98.6%
Sep-12	$99,154,010	($16,477,176)	$179,647,915	($96,844,326)	$38,699,241	46.8%	75.4%
Oct-12	$68,051,707	($9,827,426)	$137,698,279	($79,454,756)	$24,321,860	41.8%	75.4%
Nov-12	$66,233,739	($6,557,217)	$124,142,020	($64,424,379)	$52,049,442	87.2%	93.8%
Dec-12	$54,866,078	($4,610,245)	$110,328,974	($59,848,711)	$36,295,666	72.2%	87.1%
Total	$882,280,937	($112,877,538)	$1,725,393,160	($955,277,987)	$565,170,652	73.5%	88.1%

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 12-30 shows the monthly positive, negative and total target allocations.[33] Table 12-30 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 $53.9 million in revenue available to fund 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 2012 from the reported 73.5 percent to 91.2 percent.

33 Reported payout ratio may differ between Table 12-27 and Table 12-28 due to rounding differences when netting target allocations and considering each FTR individually.

Table 12-30 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-12	$126,702,422	($64,766,863)	$61,935,560	$49,465,924	79.9%	$114,232,786	92.6%	$117,367,780
Feb-12	$124,792,575	($67,369,848)	$57,422,727	$38,390,571	66.9%	$105,760,419	88.7%	$110,681,339
Mar-12	$147,644,281	($89,829,450)	$57,814,831	$48,331,587	83.6%	$138,161,037	95.2%	$140,519,040
Apr-12	$190,422,018	($116,820,310)	$73,601,707	$40,645,388	55.2%	$157,465,699	87.0%	$165,641,014
May-12	$177,551,934	($108,239,496)	$69,312,438	$53,188,585	76.7%	$161,428,081	93.3%	$165,734,697
Jun-12	$121,217,938	($58,280,956)	$62,936,981	$58,463,402	92.9%	$116,744,359	97.1%	$117,660,567
Jul-12	$173,602,611	($93,421,963)	$80,180,649	$71,254,665	88.9%	$164,676,628	96.1%	$166,755,703
Aug-12	$111,642,193	($55,976,928)	$55,665,265	$54,064,320	97.1%	$110,041,248	98.9%	$110,403,489
Sep-12	$179,647,915	($96,844,326)	$82,803,589	$38,699,241	46.7%	$135,543,567	82.3%	$147,775,239
Oct-12	$137,698,279	($79,454,756)	$58,243,523	$24,321,860	41.8%	$103,776,616	82.5%	$113,612,324
Nov-12	$124,142,020	($64,424,379)	$59,717,640	$52,049,442	87.2%	$116,473,822	95.3%	$118,341,423
Dec-12	$110,328,974	($59,848,711)	$50,480,263	$36,295,666	71.9%	$96,144,377	90.5%	$99,840,410
Total	$1,725,393,160	($955,277,987)	$770,115,174	$565,170,652	73.4%	$1,520,448,638	91.2%	$1,574,333,025

* Reported payout ratios may vary due to rounding differences when netting

Figure 12-16 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through December 2012.

Figure 12-16 FTR Surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through December 2012

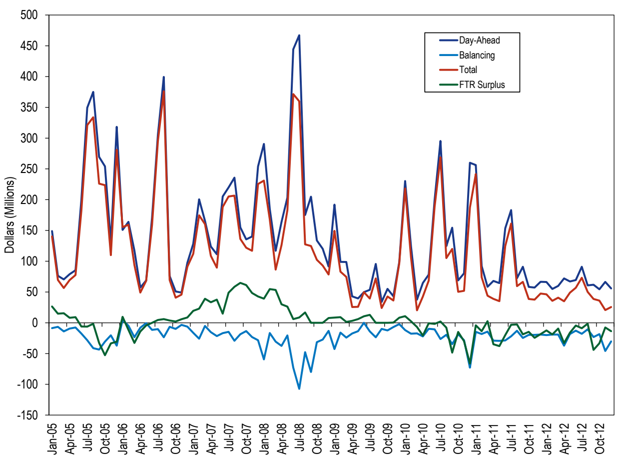
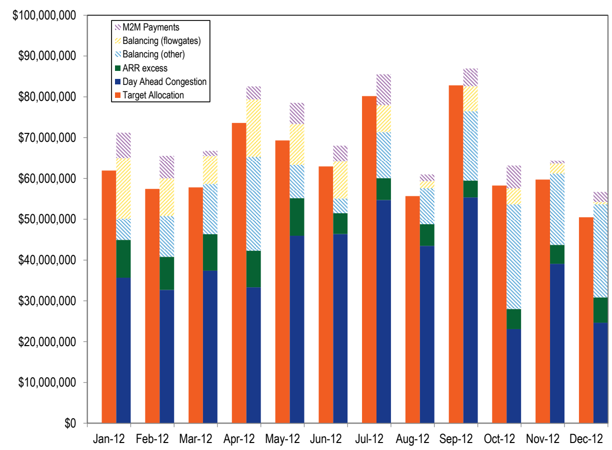


Figure 12-17 shows the monthly target allocation compared to the available positive and negative congestion revenue. The solid orange bar on the left of each month shows the monthly target allocation for all FTRs. The bar on the right of each month shows the positive and negative congestion dollars available to fund target allocations. The total height of the bar corresponds to total Day-Ahead congestion. Striped areas on this bar represent charges that reduce revenue and solid areas represent additions to revenue.

Figure 12-17 shows the relationship among balancing congestion, M2M payments and day-ahead congestion.

In the beginning of the year balancing congestion from flowgates comprised a majority of the total balancing congestion, but towards the end of the year it became a smaller proportion of total balancing congestion.

Figure 12-17 FTR target allocation compared to sources of positive and negative congestion revenue



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.[34] 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

34 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.

FTR auction participants' expectations of locational congestion price differences and the associated level of revenue sufficiency.

ARRs are available only as obligations (not options) and only as the 24-hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the price difference between sink and source, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than the sum of all ARR target allocations, ARRs are fully funded. If these revenues are less than the sum of all ARR target allocations, available revenue is proportionally allocated among all ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network Service Users and Firm Transmission Customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs are reallocated, as load shifts between LSEs within the transmission zone.

IARRs are allocated to customers that have been assigned cost responsibility for certain upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP). These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each Regionally Assigned Facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their percentage of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[35] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

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 2012 to 2013 planning period, all eligible market participants were allocated ARRs.

Supply and Demand

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible. The top three binding transmission constraints for the 2011 to 2012 planning period are shown in Figure 12-1.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[36] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis. Long Term ARR holders can self schedule their Long Term ARRs as FTRs for any planning period during the 10 planning period timeline.

Each March, PJM allocates ARRs to eligible customers in a three-stage process:

35 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2011/2012 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2011-2012/iarrs-rtep-upgrades-allocated-for-2011-12-planning-period.ashx>.

36 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[37]
- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation for the following planning period. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.
- **Stage 2.** Stage 2 of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[38] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015 to 2016 planning period, when residual zone pricing will be introduced, an ARR will default to sinking at the load settlement point, but the ARR holder may elect to sink their ARR at the physical zone instead.[39]

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on assumptions about the configuration and availability of transmission capability during the planning period.[40] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 12-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) X (Individual requested MW / Total requested MW) X (1 / MW effect on line).[41]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution

37 See PJM. "Manual 6: Financial Transmission Rights" Revision 12 (July 1, 2009), p. 22.

38 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 21.

39 See "Residual Zone Pricing," PJM Presentation to the Members Committee (February 23, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mc/20120223/20120223-item-03-residual-zone-pricing-presentation.ashx> The introduction of residual zone pricing, while approved by PJM members, depends on a FERC order.

40 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 54-55.

41 See the *MMU Technical Reference for PJM Markets*, at "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates ARR requests in proportion to their MW value and the impact on the binding constraint. PJM's method results in the prorating only of ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs.

Table 12-31 shows the top 10 principal binding transmission constraints, along with their corresponding control zones, in order of severity that limited the 2012 to 2013 ARR allocation. The order of severity is determined by the violation degree of the binding constraint as computed in the simultaneous feasibility test and provides a measurement of the MW that a constraint is over the limit. For the 2012 to 2013 ARR Stage 1A allocation PJM was required to increase the capability limits above their actual ratings for several facilities in order to make the ARR allocation feasible.[42]

Table 12-31 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2012 to 2013

Constraint	Type	Control Zone
Pleasant Prairie - Zion	Flowgate	MISO
Breed - Wheatland	Flowgate	MISO
Silver Lake	Transformer	ComEd
Oak Grove - Galesburg	Flowgate	MISO
Kenosha - Lakeview	Flowgate	MISO
Nucor - Whitestown	Flowgate	MISO
South Mahwah - Waldwick	Line	PSEG
Belvidere - Woodstock	Line	ComEd
East Frankfort - Braidwood	Line	ComEd
Pleasant Valley - Crystal Lake	Line	ComEd

ARR Reassignment for Retail Load Switching

Current 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.[43] 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 ARR for the receiving LSE compared to the total value held by the original ARR holder.

There were 22,543 MW of ARRs associated with approximately $226,900 of revenue that were reassigned in the first seven months of the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758,900 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Table 12-32 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2011 and December 2012.

Table 12-32 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2011, through December 31, 2012

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2011/2012 (12 months)	2012/2013 (7 months)*	2011/2012 (12 months)	2012/2013 (7 months)*
AECO	563	287	$4.8	$1.5
AEP	6,341	2,249	$119.0	$27.9
AP	5,516	2,660	$319.4	$63.2
ATSI	3,321	2,246	$13.3	$4.1
BGE	2,745	1,278	$45.9	$15.2
ComEd	3,804	4,225	$59.1	$60.7
DAY	463	260	$0.6	$0.4
DEOK	NA	1,116	NA	$0.6
DLCO	2,964	1,120	$10.4	$8.0
DPL	1,957	917	$15.4	$5.1
Dominion	1	0	$0.0	$0.0
JCPL	1,332	715	$10.1	$2.8
Met-Ed	1,273	515	$20.9	$3.6
PECO	1,994	784	$21.9	$5.0
PENELEC	1,116	420	$21.2	$3.8
PPL	3,565	1,290	$38.1	$7.9
PSEG	2,325	1,201	$31.2	$8.4
Pepco	2,489	1,261	$27.4	$8.6
RECO	73	33	$0.0	$0.0
Total	41,770	22,543	$758.9	$226.9

* Through 31-Dec-2012

42 It is a requirement of Section 7.4.2 (i) in the OATT that any ARR request made in Stage 1A must be feasible and transmission capability must be raised if an ARR request is found to be infeasible.

43 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

Incremental ARRs

Market participants constructing generation interconnection or transmission expansion projects may request an allocation of incremental ARRs based on the resultant increase in transmission capability.[44] Incremental ARRs are available in a three-round allocation process with a single point-to-point combination requested and one-third of the incremental ARR MW allocated in each round. Incremental ARRs can be accepted or refused after rounds one and two. Incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall the system simultaneous feasibility can be maintained.

Table 12-33 lists the incremental ARR allocation volume for the current and previous planning periods from the 2008 to 2009 planning period through the 2012 to 2013 planning periods. For the 2012 to 2013 planning period there were requests for 687.4 MW and all of the bids were cleared.

Table 12-33 Incremental ARR allocation volume: Planning periods 2008 to 2009 through 2012 to 2013

Planning Period	Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	891	891	100%	0	0%
2009/2010	14	531	531	100%	0	0%
2010/2011	14	531	531	100%	0	0%
2011/2012	15	595	595	100%	0	0%
2012/2013	15	687.4	687.4	100%	0	0%

Incremental ARRs (IARRs) for RTEP Upgrades

IARRs are allocated to customers that have been assigned cost responsibility for certain upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP). These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each Regionally Assigned Facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their percentage of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[45] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

Table 12-34 lists the three RTEP upgrade projects that were allocated a total of 678.2 MW of IARRs.

Table 12-34 IARRs allocated for 2012 to 2013 Annual ARR Allocation for RTEP upgrades[46]

		IARR Parameters		
Project #	Project Description	Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	190.6
B0328	TrAIL Project: 502 JCT - Loudoun 500kV	RTEP B0328 Source	Pepco	391.2
B0329	Cason-Suffolk 500 kV	RTEP B0329 Source	Dominion	96.4

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

44 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 30.

45 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2011/2012 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2011-2012/iarrs-rtep-upgrades-allocated-for-2011-12-planning-period.ashx>.

46 RTEP B0287 Source is a new aggregate comprised of an equal ten percent weighting of the following ten pnodes: MUDDYRN 13 KV Unit1, MUDDYRN 13 KV Unit2, MUDDYRN 13 KV Unit3, MUDDYRN 13 KV Unit4, MUDDYRN 13 KV Unit5, MUDDYRN 13 KV Unit6, MUDDYRN 13 KV Unit7, MUDDYRN 13 KV Unit8, PEACHBOT 22 KV UNIT02 and PEACHBOT 22 KV UNIT03.

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 12-35 shows the Residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 12-35 Residual ARR allocation volume and target allocation

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Aug-12	4,508.2	2,460.5	54.6%	$1,026,836
Sep-12	4,696.3	2,343.1	49.9%	$1,003,031
Oct-12	6,502.2	1,698.9	26.1%	$584,810
Nov-12	3,677.8	1,530.6	41.6%	$393,221
Dec-12	7,006.6	1,614.5	23.0%	$463,325

Market Performance

Volume

Table 12-36 Annual ARR allocation volume: Planning periods 2011 to 2012 and 2012 to 2013

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2011/2012	1A	0	12,654	64,160	64,160	100.0%	0	0.0%
	1B	1	7,660	27,325	22,208	81.3%	5,117	18.7%
	2	2	3,498	20,321	3,072	15.1%	17,249	84.9%
		3	2,593	18,538	6,653	35.9%	11,885	64.1%
		4	2,080	18,194	6,383	35.1%	11,811	64.9%
		Total	8,171	57,053	16,108	28.2%	40,945	71.8%
	Total		28,485	148,538	102,476	69.0%	46,062	31.0%
2012/2013	1A	0	16,069	67,302	67,300	100.0%	2	0.0%
	1B	1	11,487	30,013	18,432	61.4%	11,581	38.6%
	2	2	4,887	22,597	2,701	12.0%	19,896	88.0%
		3	3,682	22,496	3,334	14.8%	19,162	85.2%
		4	3,023	22,362	6,219	27.8%	16,143	72.2%
		Total	11,592	67,455	12,254	18.2%	55,201	81.8%
	Total		39,148	164,770	97,986	59.5%	66,784	40.5%

Table 12-36 shows the volume of ARR allocations for each round for the 2011 to 2012 and 2012 to 2013 planning periods. For the 2012 to 2013 planning period there were 67,302 MW (40.8 percent of total demand) requested in Stage 1A, 30,013 MW (18.2 percent of total demand) requested in Stage 1B and 67,455 MW (40.9 percent of total demand) requested in Stage 2. Of 164,770 MW in total requests, 67,300 MW were allocated in Stage 1A, with 2.7 MW relinquished, 18,432 MW were allocated in Stage 1B and 12,254 MW were allocated in Stage 2 for a total of 98,986 MW (59.5 percent) allocated. Eligible market participants subsequently self scheduled 41,716 MW (42.1 percent) of these ARRs as FTRs, leaving 57,270 MW of ARRs outstanding. For the 2011 to 2012 planning period there were 64,160 MW (43.2 percent of total demand) requested in Stage 1A, 22,208 MW (18.4 percent of demand) requested in Stage 1B and 57,053 MW (38.4 MW of total demand) requested in Stage 2. Of 148,538 MW in total ARR requests, 64,160 MW were allocated in Stage 1A, 22,208 were allocated in Stage 1B and 16,108 were allocated in Stage 2 for a total of 102,476 MW (69.0 percent). ARR holders did not relinquish any ARRs for the 2011 to 2012 planning period.

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine transmission upgrades so that the long term ARRs can remain feasible. If a simultaneous feasibility test violation occurs in any year of this test PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be included in the PJM RTEP process.

For the 2012 to 2013 planning period, Stage 1A of the Annual ARR Allocation was infeasible. According to Section 7.4.2 (i) of the PJM OATT the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and that these increased limits must then be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. These infeasibilities are due to newly monitored facilities where upgrades could not be planned in advance, facilities not owned by PJM and an overall reduced system capability.

The consequence of this increased capability in the models which does not reflect actual capability is an over allocation of both ARRs and FTRs for the entire planning period. In the case of ARRs this over allocation will lower the ARR funding level by selling more capability on the same transmission network. In the case of FTRs the over allocation will exacerbate the underfunding problem by selling more FTRs than are physically feasible with no increase in congestion collected.

Table 12-37 lists the constraints for which ARR requests were found to be infeasible for the 2012 to 2013 ARR Stage 1A Allocation and the MW increase in modeled facility ratings required to make them feasible.

Table 12-37 Constraints with capacity increases due to Stage 1A infeasibility for the 2012 to 2013 ARR Allocation

Constraint	Type	Control Zone	MW Increase
Pleasant Prairie - Zion	Flowgate	MISO	311
Breed - Wheatland	Flowgate	MISO	221
Silver Lake	Transformer	ComEd	131
Oak Grove - Galesburg	Flowgate	MISO	96
Kenosha - Lakeview	Flowgate	MISO	73
Belvidere - Woodstock	Line	ComEd	23
Harwood - Susquehanna	Line	PPL	16
Belmont	Transformer	AP	14
Nucor - Whitestown	Flowgate	MISO	7

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 $620.2 million in credits from the Annual FTR Auction during the 2012 to 2013 planning period, with an average hourly ARR credit of $0.63 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 $1.05 per MW.

Table 12-38 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2011 to 2012 and the 2012 to 2013 (through December 31, 2012) planning periods.

Table 12-38 ARR revenue adequacy (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013

	2011/2012	2012/2013
Total FTR auction net revenue	$1,055.9	$620.2
Annual FTR Auction net revenue	$1,029.6	$602.9
Monthly Balance of Planning Period FTR Auction net revenue*	$26.3	$17.3
ARR target allocations	$947.3	$565.4
ARR credits	$947.3	$565.4
Surplus auction revenue	$108.6	$54.7
ARR payout ratio	100%	100%
FTR payout ratio*	80.6%	74.8%

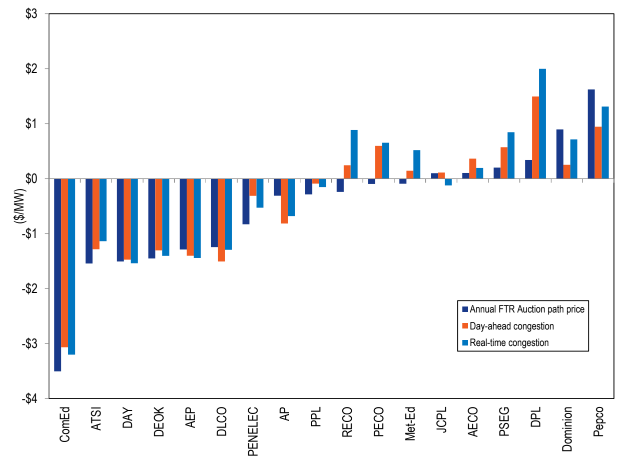
* Shows twelve months for 2011/2012 seven months for 2012/2013.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 12-18 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2012 to 2013 planning period. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 12-18 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub[47]: Planning period 2011 to 2012



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 seven months of the 2012 to 2013 planning period, the total revenues received by the holders of all ARRs and FTRs offset 82.1 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 12-39. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[48] 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 74.8 percent of the target allocation for the first seven months of the 2012 to 2013 planning period. 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.

47 DEOK was integrated into PJM on January 1, 2012 so was not available in the 2011 to 2012 Annual FTR Auction and therefore is not included in Figure 12-19.

48 For Table 12-37 through Table 12-39, 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.

Table 12-39 ARR and self-scheduled FTR congestion offset (in millions) by control zone: Planning period 2012 to 2013[49]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$5.9	$0.0	$5.9	$6.3	($0.3)	94.4%
AEP	$25.1	$31.1	$56.2	$36.8	$29.9	>100%
APS	$40.3	$12.1	$52.5	$5.7	$50.9	>100%
ATSI	$4.1	$0.1	$4.2	($1.3)	$5.6	>100%
BGE	$30.2	$0.4	$30.6	$4.1	$26.6	>100%
ComEd	$101.8	$0.0	$101.8	($38.1)	$140.0	>100%
DAY	$1.5	$1.2	$2.7	($1.2)	$4.3	>100%
DEOK	$1.1	$0.0	$1.1	$4.0	($2.8)	28.4%
DLCO	$5.9	$0.3	$6.2	($0.2)	$6.5	>100%
Dominion	$4.8	$33.3	$38.1	$11.9	$37.4	>100%
DPL	$11.5	$1.3	$12.8	$27.0	($13.7)	47.5%
External	$5.7	$0.2	$5.9	$2.7	$3.3	>100%
JCPL	$9.0	($0.0)	$9.0	$7.8	$1.1	>100%
Met-Ed	$8.7	$0.1	$8.8	$4.2	$4.7	>100%
PECO	$16.9	$2.3	$19.3	$3.0	$17.0	>100%
PENELEC	$6.9	$3.1	$10.0	$8.1	$2.9	>100%
Pepco	$24.8	$0.7	$25.5	$22.7	$3.1	>100%
PPL	$17.6	$0.8	$18.4	$5.6	$13.1	>100%
PSEG	$26.1	$2.8	$28.9	$2.1	$27.7	>100%
RECO	$0.0	$0.0	$0.0	$0.8	($0.8)	0.2%
Total	$347.9	$90.1	$438.0	$111.9	$370.5	>100%

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 12-40 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 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 74.8 percent of the target allocation for the 2012 to 2013 planning period. 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.[50] The last column shows the difference between the total ARR and FTR offset and the congestion cost for each control zone.

49 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.

50 The total zonal congestion numbers were calculated as of March 8, 2013 and may change as a result of continued PJM billing updates.

Table 12-40 ARR and FTR congestion offset (in millions) by control zone: Planning period 2012 to 2013

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$5.9	$0.4	$5.8	$0.6	$5.9	($5.3)	10.3%
AEP	$107.1	$56.6	$121.7	$42.0	$66.7	($24.7)	63.0%
APS	$76.2	$13.6	$40.3	$49.5	$36.3	$13.2	>100%
ATSI	$4.3	$10.0	($0.7)	$15.0	$2.4	$12.6	>100%
BGE	$31.5	$14.6	$42.3	$3.9	$16.0	($12.1)	24.4%
ComEd	$121.4	$68.1	$82.7	$106.8	$107.0	($0.2)	99.8%
DAY	$3.8	$3.6	$5.3	$2.1	$4.9	($2.8)	42.5%
DEOK	$1.4	$5.7	$3.9	$3.1	$2.6	$0.5	>100%
DLCO	$7.2	$0.4	$7.7	($0.1)	$1.4	($1.5)	0.0%
Dominion	$79.3	$49.3	$110.1	$18.5	$43.1	($24.7)	42.8%
DPL	$12.3	$24.0	$19.3	$17.0	$16.6	$0.4	>100%
External	$7.5	($1.6)	$1.7	$4.2	($30.4)	$34.6	>100%
JCPL	$9.3	$3.3	$20.1	($7.5)	$9.2	($16.7)	0.0%
Met-Ed	$9.0	$6.2	$15.9	($0.6)	$0.2	($0.8)	0.0%
PECO	$20.1	$17.8	$18.1	$19.8	($1.2)	$21.0	>100%
PENELEC	$11.8	$18.2	$30.8	($0.8)	$19.1	($19.9)	0.0%
Pepco	$27.1	$18.9	$81.0	($35.0)	$16.5	($51.5)	0.0%
PPL	$20.2	$4.4	$10.3	$14.3	$8.0	$6.3	>100%
PSEG	$24.0	$19.1	$33.0	$10.0	($3.2)	$13.2	>100%
RECO	$0.0	($0.1)	($1.8)	$1.7	$0.9	$0.8	>100%
Total	$579.6	$332.6	$647.6	$264.6	$322.1	($57.5)	82.1%

Table 12-41 shows the total offset due to ARRs and FTRs for the entire 2011 to 2012 planning period and the first seven months of the 2012 to 2013 planning period.

Table 12-41 ARR and FTR congestion hedging (in millions): Planning periods 2011 to 2012 and 2012 to 2013 through December 31, 2012[51]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2011/2012	$982.9	$794.3	$1,092.4	$684.8	$771.2	($86.4)	88.8%
2012/2013*	$579.6	$332.6	$647.6	$264.6	$322.1	($57.5)	82.1%

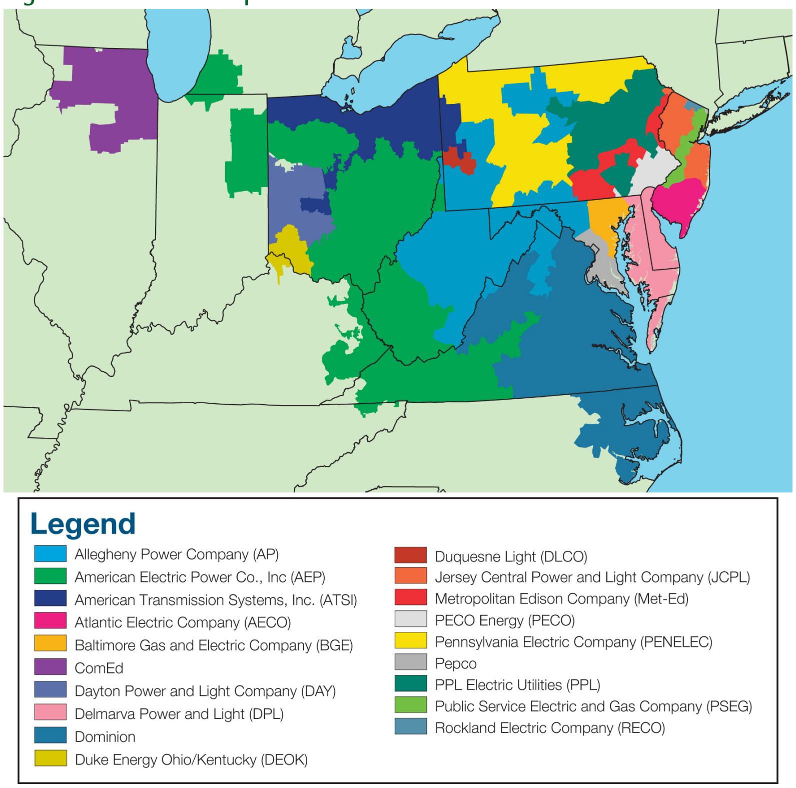
* Shows seven months ended 31-Dec-12

51 The FTR credits do not include after-the-fact adjustments. For the 2012 to 2013 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.

PJM Geography

During 2012, the PJM geographic footprint encompassed 19 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure A-1 PJM's footprint and its 19 control zones



Analysis of 2012 market results requires comparison to 2011 and certain other prior years. In 2012, PJM integrated the Duke Energy Ohio and Kentucky (DEOK) Control Zone. In 2011, PJM integrated the ATSI Control Zone. In 2006 through 2010 the PJM footprint was stable. In 2004 and 2005, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[1]

- **Phase 1 (2004).** The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[2] and the Allegheny Power Company (AP) Control Zone.[3]
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[4]
- **Phase 3 (2004).** The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.
- **Phase 4 (2005).** The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.
- **Phase 5 (2005 through 2011).** The period from May 1, 2005, through May 31, 2011, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.
- **Phase 6 (2011).** The period from June 1, through December 31, 2011 during which PJM was comprised of the Phase 5 elements plus the ATSI Control Zone which was integrated into PJM on June 1, 2011.

1 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

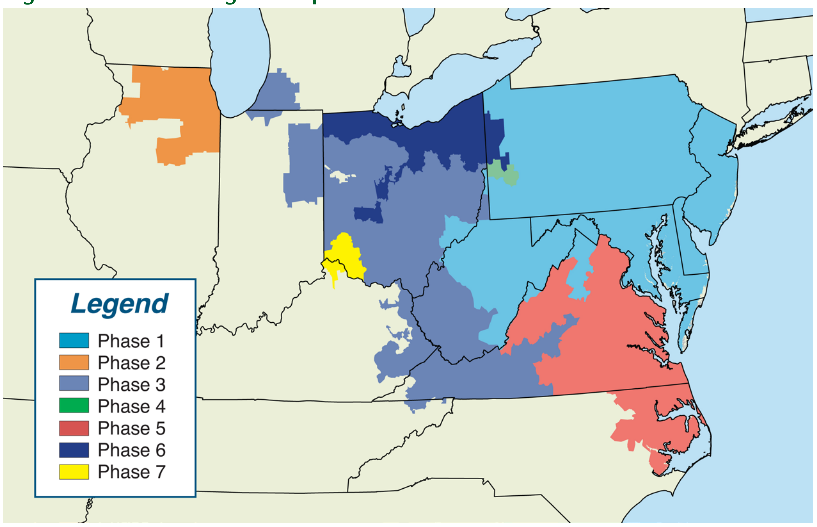
2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

4 During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

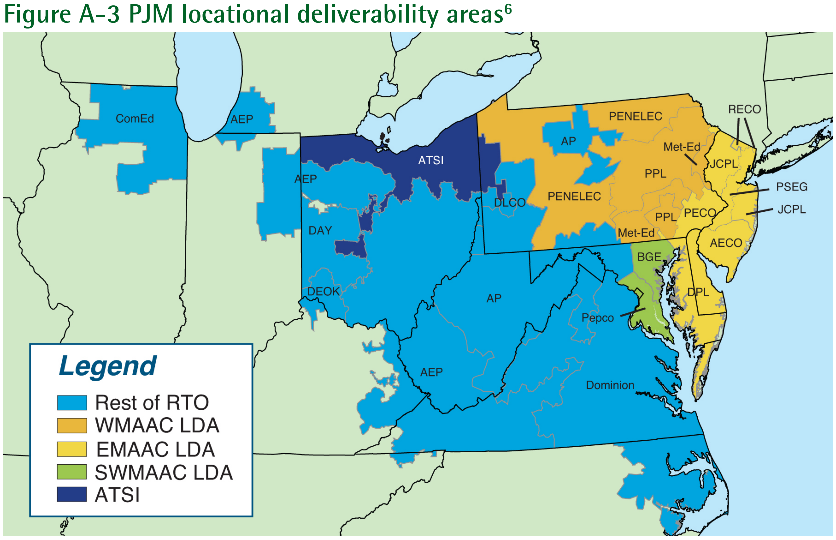
- **Phase 7 (2012).** The period from January 1, 2012, through the present, during which PJM was comprised of the Phase 6 elements plus the DEOK Control Zone which was integrated into PJM on January 1, 2012.

Figure A-2 PJM integration phases



A locational deliverability area (LDA)[5], defined as part of the RPM capacity market, is a Control Zone or part of a Control Zone within PJM with defined internal generation and defined transmission capability to import capacity in the RPM design.

Figure A-3 PJM locational deliverability areas[6]



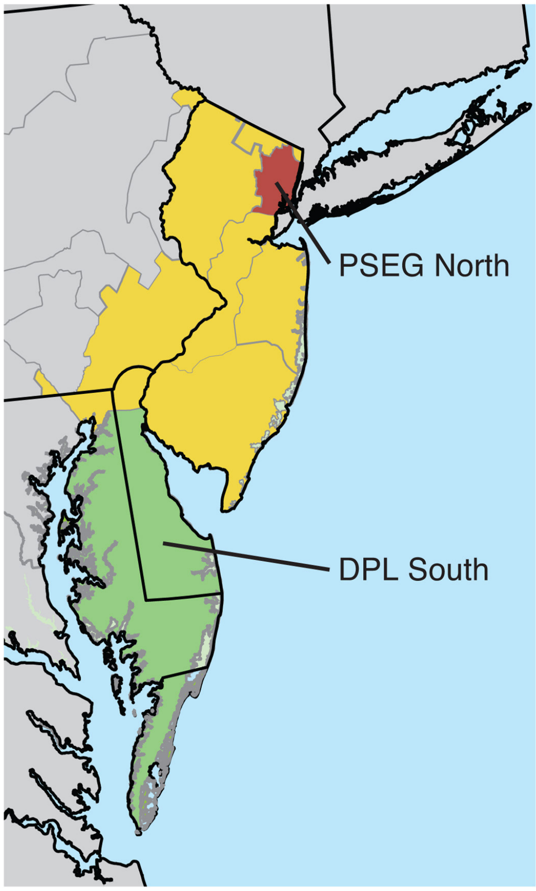
In PJM's Reliability Pricing Model (RPM) Auctions, an LDA becomes a separate market when it cannot meet its reliability requirements through a combination of economic merit order imports and internal generation without the purchase of out of merit capacity within the LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price, and the RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 Base Residual Auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 Base Residual Auction, the defined markets were RTO, MAAC+APS and SWMAAC. The MAAC+APS LDA consists of the WMAAC, EMAAC, and SWMAAC LDAs, as shown in Figure A-3, plus the Allegheny Power System (APS or AP) Zone as shown in Figure A-1. For the 2010/2011 Base Residual Auction, the defined markets were RTO and DPL South. The DPL South LDA is shown in Figure A-4. For the 2011/2012 Base Residual Auction, the only defined market was RTO. For the 2012/2013 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, PSEG North, and DPL South. The PSEG North LDA is shown in Figure A-4. For the 2013/2014 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, and Pepco. For the 2014/2015 Base Residual Auction, the defined markets were RTO, MAAC, and PSEG North. For the 2015/2016 Base Residual Auction, the defined markets were RTO, MAAC, and ATSI.

5 OATT Attachment DD § 2.38.

6 The ATSI Control Zone integration into PJM was effective beginning with the 2011/2012 delivery year. The ATSI Control Zone is considered a non-MAAC LDA.

Figure A-4 PJM RPM EMAAC locational deliverability area, including PSEG North and DPL South



PJM Market Milestones

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Marginal loss component in LMPs
2008	June	Day-Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve accounting rules
	December	Three Pivotal Supplier Test in Regulation Market
2011	June	Integration of ATSI Control Zone into PJM
2012	January	Integration of DEOK Control Zone into PJM
	October	Regulation Market: Slow and fast frequency response
	October	Scarcity pricing in Energy Market

Energy Market

This appendix provides more detailed information about load, locational marginal prices (LMP) and offer-capped units.

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM accounting load by hour, for 2007 to 2012.[1] The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the load was between 0 GWh and 20 GWh and then within a given 5-GWh load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone in 2002, the ComEd, AEP and DAY control zones in 2004, the DLCO and Dominion control zones in 2005 , the ATSI Control Zone in 2011 and the DEOK Control Zone in 2012 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2012 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak load in 2012 was 21.7 percent higher than off-peak load in 2012. Average load during on-peak hours in 2012 was 5.2 percent higher than in 2011. Off-peak load in 2012 was 5.7 percent higher than in 2011 (Table C-3).

Table C-1 Frequency distribution of PJM real-time, hourly load: 2007 to 2012

	2007		2008		2009		2010		2011		2012	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	15	0.17%	12	0.14%	5	0.06%	0	0.00%
50 to 55	79	0.90%	127	1.45%	376	4.46%	272	3.24%	104	1.24%	0	0.00%
55 to 60	433	5.84%	517	7.33%	738	12.89%	582	9.89%	325	4.95%	104	1.18%
60 to 65	637	13.12%	667	14.92%	836	22.43%	699	17.87%	602	11.83%	471	6.55%
65 to 70	890	23.28%	941	25.64%	915	32.88%	805	27.05%	858	21.62%	629	13.71%
70 to 75	878	33.30%	1,048	37.57%	1,342	48.20%	1,323	42.16%	1,120	34.41%	785	22.64%
75 to 80	1,227	47.31%	1,535	55.04%	1,488	65.18%	1,272	56.68%	1,176	47.83%	1,010	34.14%
80 to 85	1,338	62.58%	1,208	68.80%	966	76.21%	948	67.50%	1,259	62.20%	1,390	49.97%
85 to 90	981	73.78%	916	79.22%	742	84.68%	794	76.56%	1,024	73.89%	1,233	64.00%
90 to 95	741	82.24%	655	86.68%	549	90.95%	659	84.09%	719	82.10%	973	75.08%
95 to 100	577	88.82%	457	91.88%	388	95.38%	487	89.65%	495	87.75%	690	82.93%
100 to 105	382	93.18%	292	95.21%	205	97.72%	318	93.28%	279	90.94%	437	87.91%
105 to 110	223	95.73%	181	97.27%	121	99.10%	195	95.50%	194	93.15%	289	91.20%
110 to 115	179	97.77%	133	98.78%	48	99.65%	151	97.23%	173	95.13%	185	93.31%
115 to 120	106	98.98%	58	99.44%	26	99.94%	108	98.46%	149	96.83%	152	95.04%
120 to 125	43	99.47%	35	99.84%	5	100.00%	84	99.42%	95	97.91%	135	96.57%
125 to 130	31	99.83%	14	100.00%	0	100.00%	40	99.87%	68	98.69%	121	97.95%
130 to 135	12	99.97%	0	100.00%	0	100.00%	11	100.00%	49	99.25%	77	98.83%
135 to 140	3	100.00%	0	100.00%	0	100.00%	0	100.00%	35	99.65%	46	99.35%
> 140	0	100.00%	0	100.00%	0	100.00%	0	100.00%	31	100.00%	57	100.00%

1 The definitions of load are discussed in the Technical Reference for PJM Markets, Section 5, "Load Definitions."

2 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Table C-2 Off-peak and on-peak load (MW): 1998 to 2012

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98
2009	68,745	84,337	1.23	67,159	81,825	1.22	10,924	10,523	0.96
2010	72,186	88,066	1.22	70,318	85,435	1.21	12,942	13,753	1.06
2011	74,815	91,413	1.22	72,661	87,938	1.21	12,978	14,835	1.14
2012	79,047	96,194	1.22	76,930	92,199	1.20	13,182	14,426	1.09

Table C-3 Multiyear change in load: 1998 to 2012

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.7%)	4.3%	2.8%	(1.4%)	20.9%	9.9%	(9.1%)
2000	1.8%	1.6%	(0.2%)	2.1%	2.5%	0.5%	(9.7%)	(13.3%)	(4.0%)
2001	(0.4%)	1.5%	1.9%	0.5%	1.0%	0.5%	(5.4%)	16.0%	22.6%
2002	18.4%	17.5%	(0.7%)	15.7%	16.0%	0.2%	44.6%	53.9%	6.4%
2003	5.9%	3.6%	(2.2%)	7.8%	6.4%	(1.3%)	(9.3%)	(27.3%)	(19.9%)
2004	32.8%	34.2%	1.0%	30.5%	38.7%	6.3%	95.6%	132.2%	18.7%
2005	57.5%	55.6%	(1.2%)	58.2%	45.8%	(7.8%)	17.4%	21.0%	3.0%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	(0.5%)	(10.9%)	(16.9%)	(6.8%)
2007	2.4%	3.1%	0.7%	2.1%	4.3%	2.2%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.7%)	(1.7%)	(3.5%)	(1.8%)	(1.1%)	(6.0%)	(5.0%)
2009	(4.8%)	(4.1%)	0.7%	(4.8%)	(4.2%)	0.6%	(4.0%)	(6.1%)	(2.2%)
2010	5.0%	4.4%	(0.6%)	4.7%	4.4%	(0.3%)	18.5%	30.7%	10.3%
2011	3.6%	3.8%	0.2%	3.3%	2.9%	(0.4%)	0.3%	7.9%	7.6%
2012	5.7%	5.2%	(0.4%)	5.9%	4.8%	(1.0%)	1.6%	(2.8%)	(4.3%)

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the Market Monitoring Unit (MMU) examines three measures: average LMP; load-weighted average LMP; and fuel-cost-adjusted, load-weighted average LMP. Differences in average LMP measure the change in reported price. Differences in load-weighted average LMP measure the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Differences in fuel-cost-adjusted, load-weighted average LMP measure the change in reported price actually paid by load after accounting for the change in price that reflects changes in fuel prices.[3]

Any Load Serving Entity (LSE) may request to settle at a bus LMP or aggregate LMP per rules in PJM Manual 27. The zonal LMP includes every bus in the zone and is not affected by the choices of LSEs. The zonal LMP is defined by weighting each load bus LMP by its hourly individual load bus contribution to the total zonal load. The LMP for a defined aggregate is calculated by weighting each included load bus LMP by its hourly contribution to the total load of the defined aggregate.

In the Day-Ahead Energy Market buyers may submit bids at specific locations such as a transmission zone, aggregate or a single bus. Price sensitive demand bids specify price and MW quantities and a location for the bid. Market participants may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interfaces. PJM provides the definitions of the transmission zones, aggregates, and single buses.[4]

3 See the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price."

4 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 57 (December 1, 2012), Section 2, pp. 16.

Real-Time LMP

Frequency Distribution of Real-Time Average LMP

Table C-4 provides frequency distributions of PJM real-time hourly average LMP for 2007 to 2012. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM real-time LMP was within a given $10 per MWh price interval and lower than $300 per MWh, or within a given $100 per MWh price interval and higher than $300 per MWh, or for the cumulative column, within the interval plus all the lower price intervals.

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): 2007 to 2012

	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	56	0.64%	94	1.07%	117	1.34%	65	0.74%	66	0.75%	131	1.49%
$10 to $20	185	2.75%	129	2.54%	218	3.82%	127	2.19%	89	1.77%	510	7.30%
$20 to $30	1,571	20.68%	490	8.12%	2,970	37.73%	1,810	22.85%	1,764	21.91%	4,002	52.86%
$30 to $40	1,470	37.47%	1,443	24.54%	2,951	71.42%	3,150	58.81%	3,967	67.19%	2,801	84.74%
$40 to $50	1,108	50.11%	1,533	42.00%	1,269	85.90%	1,462	75.50%	1,334	82.42%	668	92.35%
$50 to $60	931	60.74%	1,212	55.79%	555	92.24%	766	84.25%	489	88.00%	244	95.13%
$60 to $70	827	70.18%	845	65.41%	276	95.39%	427	89.12%	303	91.46%	136	96.68%
$70 to $80	726	78.47%	709	73.49%	151	97.11%	274	92.25%	174	93.45%	75	97.53%
$80 to $90	646	85.84%	502	79.20%	95	98.20%	165	94.13%	133	94.97%	51	98.11%
$90 to $100	451	90.99%	385	83.58%	62	98.90%	134	95.66%	108	96.20%	38	98.54%
$100 to $110	240	93.73%	352	87.59%	30	99.25%	82	96.60%	61	96.89%	32	98.91%
$110 to $120	178	95.76%	265	90.61%	21	99.49%	71	97.41%	61	97.59%	20	99.13%
$120 to $130	110	97.02%	199	92.87%	15	99.66%	61	98.11%	46	98.12%	15	99.31%
$130 to $140	76	97.89%	144	94.51%	7	99.74%	44	98.61%	33	98.49%	10	99.42%
$140 to $150	53	98.49%	111	95.78%	9	99.84%	29	98.94%	25	98.78%	7	99.50%
$150 to $160	26	98.79%	102	96.94%	3	99.87%	22	99.19%	25	99.06%	8	99.59%
$160 to $170	29	99.12%	68	97.71%	3	99.91%	11	99.32%	17	99.26%	5	99.65%
$170 to $180	18	99.33%	52	98.30%	5	99.97%	13	99.46%	15	99.43%	1	99.66%
$180 to $190	9	99.43%	45	98.82%	0	99.97%	12	99.60%	6	99.50%	2	99.68%
$190 to $200	15	99.60%	29	99.15%	1	99.98%	9	99.70%	8	99.59%	3	99.72%
$200 to $210	6	99.67%	20	99.37%	1	99.99%	7	99.78%	6	99.66%	2	99.74%
$210 to $220	4	99.71%	11	99.50%	1	100.00%	4	99.83%	5	99.71%	1	99.75%
$220 to $230	4	99.76%	14	99.66%	0	100.00%	3	99.86%	4	99.76%	0	99.75%
$230 to $240	2	99.78%	10	99.77%	0	100.00%	5	99.92%	0	99.76%	4	99.80%
$240 to $250	5	99.84%	2	99.80%	0	100.00%	3	99.95%	3	99.79%	5	99.85%
$250 to $260	2	99.86%	5	99.85%	0	100.00%	1	99.97%	3	99.83%	5	99.91%
$260 to $270	4	99.91%	4	99.90%	0	100.00%	0	99.97%	3	99.86%	0	99.91%
$270 to $280	0	99.91%	1	99.91%	0	100.00%	0	99.97%	3	99.90%	1	99.92%
$280 to $290	0	99.91%	1	99.92%	0	100.00%	1	99.98%	0	99.90%	1	99.93%
$290 to $300	0	99.91%	0	99.92%	0	100.00%	0	99.98%	2	99.92%	0	99.93%
$300 to $400	2	99.93%	6	99.99%	0	100.00%	2	100.00%	4	99.97%	6	100.00%
$400 to $500	4	99.98%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$500 to $600	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$600 to $700	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
> $700	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted Average LMP

Table C-5 shows load-weighted, average real-time LMP for 2011 and 2012 during off-peak and on-peak periods.

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): 2011 to 2012

	2011			2012			Difference 2011 to 2012		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$37.28	$54.07	1.45	$28.49	$41.61	1.46	(23.6%)	(23.0%)	0.7%
Median	$32.37	$41.26	1.27	$26.89	$33.67	1.25	(16.9%)	(18.4%)	(1.7%)
Standard deviation	$20.01	$40.74	2.04	$13.56	$28.85	2.13	(32.3%)	(29.2%)	4.5%

Off-Peak and On-Peak, Real-Time, Fuel-Cost-Adjusted, Load-Weighted, Average LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up between 80 percent and 90 percent of marginal cost on average, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[5] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2011 and 2012, the load-weighted LMP for 2012 was adjusted to reflect the daily price of fuels and emission allowances used by marginal units from a base period, 2011. The fuel cost adjusted, load-weighted LMP for 2012 is compared to the load-weighted LMP for 2011.[6]

Table C-6 shows the real-time, load-weighted, average LMP for 2011 and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2012 for on-peak and off-peak hours. The fuel-cost adjusted load-weighted, average LMP for 2012 on-peak hours was 12.2 percent lower than the load-weighted, average LMP for 2011 on-peak hours. The fuel-cost adjusted load-weighted, average LMP for 2012 off-peak hours was 7.5 percent lower than the load-weighted, average LMP for 2011 off-peak hours. The mix of fuel types and costs in 2012 resulted in lower prices in 2012 than would have occurred if fuel prices had remained at their 2011 levels.

Table C-6 On-peak and off-peak real-time PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): 2012

	2011 Load-Weighted LMP	2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Off Peak	$37.28	$34.50	(7.5%)
On Peak	$54.07	$47.50	(12.2%)

PJM Real-Time, Load-Weighted Average LMP during Constrained Hours

Table C-7 shows the PJM load-weighted, average LMP during constrained hours for 2011 and 2012.[7]

Table C-7 PJM real-time load-weighted, average LMP during constrained hours (Dollars per MWh): 2011 to 2012

	2011	2012	Difference
Average	$47.36	$36.52	(22.9%)
Median	$37.05	$31.03	(16.3%)
Standard deviation	$34.90	$24.67	(29.3%)

Table C-8 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2011 and 2012.

5 See the *2012 State of the Market Report for PJM*, Volume II, Section 2,"Energy Market," at Table 2-17, "Type of fuel used (By marginal units): Calendar year 2012."

6 See the *Technical Reference for PJM Markets*, Section 7, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

7 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. 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 consistent with the way in which PJM reports real-time congestion.

Table C-8 PJM real-time load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): 2011 to 2012

	2011			2012		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$35.14	$47.36	34.8%	$26.36	$36.52	38.5%
Median	$33.21	$37.05	11.6%	$27.43	$31.03	13.1%
Standard deviation	$15.69	$34.90	122.4%	$11.56	$24.67	113.3%

Table C-9 shows the number of hours and the number of constrained hours in each month in 2011 and 2012.

Table C-9 PJM real-time constrained hours: 2011 to 2012

	2011 Constrained Hours	2012 Constrained Hours	Total Hours
Jan	678	537	744
Feb	518	633	672
Mar	578	661	743
Apr	655	669	720
May	590	632	744
Jun	622	505	720
Jul	630	676	744
Aug	658	630	744
Sep	687	649	720
Oct	717	724	744
Nov	641	663	721
Dec	669	625	744
Avg	637	634	730

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2012 were slightly higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2012 can be seen by comparing Table C-4 and Table C-10. Table C-10 shows frequency distributions of PJM day-ahead hourly LMP for the calendar years 2007 to 2012. Together the tables show the frequency distribution by hours for the two markets. In the Real-Time Energy Market, prices reached a high for the year of $398.80 per MWh on May 29, 2012, in the hour ending 1700 EPT. In the Day-Ahead Energy Market, prices reached a high for the year of $273.45 per MWh on June 21, 2012, in the hour ending 1700 EPT.

Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): 2007 to 2012

	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	3	0.03%	0	0.00%	23	0.26%	5	0.06%	0	0.00%	19	0.22%
$10 to $20	88	1.04%	19	0.22%	343	4.18%	31	0.41%	33	0.38%	467	5.53%
$20 to $30	1,291	15.78%	320	3.86%	2,380	31.35%	1,502	17.56%	1,595	18.58%	3,402	44.26%
$30 to $40	1,495	32.84%	1,148	16.93%	3,221	68.12%	2,851	50.10%	3,359	56.93%	3,521	84.35%
$40 to $50	1,221	46.78%	1,546	34.53%	1,717	87.72%	2,131	74.43%	2,024	80.03%	908	94.68%
$50 to $60	1,266	61.23%	1,491	51.50%	557	94.08%	954	85.32%	872	89.99%	247	97.50%
$60 to $70	1,301	76.08%	1,107	64.11%	253	96.96%	471	90.70%	406	94.62%	106	98.70%
$70 to $80	939	86.80%	942	74.83%	138	98.54%	302	94.14%	174	96.61%	39	99.15%
$80 to $90	504	92.56%	682	82.59%	68	99.32%	193	96.35%	87	97.60%	21	99.39%
$90 to $100	264	95.57%	542	88.76%	33	99.69%	125	97.77%	61	98.30%	12	99.52%
$100 to $110	155	97.34%	289	92.05%	19	99.91%	86	98.76%	29	98.63%	7	99.60%
$110 to $120	104	98.53%	193	94.25%	6	99.98%	46	99.28%	30	98.97%	6	99.67%
$120 to $130	59	99.20%	131	95.74%	2	100.00%	29	99.61%	16	99.16%	7	99.75%
$130 to $140	33	99.58%	112	97.02%	0	100.00%	14	99.77%	21	99.39%	4	99.80%
$140 to $150	13	99.73%	67	97.78%	0	100.00%	7	99.85%	17	99.59%	2	99.82%
$150 to $160	8	99.82%	54	98.39%	0	100.00%	6	99.92%	7	99.67%	1	99.83%
$160 to $170	7	99.90%	46	98.92%	0	100.00%	3	99.95%	3	99.70%	3	99.86%
$170 to $180	3	99.93%	23	99.18%	0	100.00%	2	99.98%	2	99.73%	1	99.87%
$180 to $190	4	99.98%	20	99.41%	0	100.00%	0	99.98%	2	99.75%	0	99.87%
$190 to $200	1	99.99%	16	99.59%	0	100.00%	2	100.00%	2	99.77%	2	99.90%
$200 to $210	1	100.00%	8	99.68%	0	100.00%	0	100.00%	1	99.78%	2	99.92%
$210 to $220	0	100.00%	9	99.78%	0	100.00%	0	100.00%	0	99.78%	2	99.94%
$220 to $230	0	100.00%	4	99.83%	0	100.00%	0	100.00%	2	99.81%	1	99.95%
$230 to $240	0	100.00%	3	99.86%	0	100.00%	0	100.00%	1	99.82%	2	99.98%
$240 to $250	0	100.00%	2	99.89%	0	100.00%	0	100.00%	0	99.82%	0	99.98%
$250 to $260	0	100.00%	0	99.89%	0	100.00%	0	100.00%	2	99.84%	1	99.99%
$260 to $270	0	100.00%	4	99.93%	0	100.00%	0	100.00%	2	99.86%	0	99.99%
$270 to $280	0	100.00%	0	99.93%	0	100.00%	0	100.00%	0	99.86%	1	100.00%
$280 to $290	0	100.00%	2	99.95%	0	100.00%	0	100.00%	0	99.86%	0	100.00%
$290 to $300	0	100.00%	2	99.98%	0	100.00%	0	100.00%	4	99.91%	0	100.00%
>$300	0	100.00%	2	100.00%	0	100.00%	0	100.00%	8	100.00%	0	100.00%

Off-Peak and On-Peak, Day-Ahead and Real-Time, Average LMP

Table C-11 shows PJM average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets in calendar year 2012. Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP in 2012 during the on-peak and off-peak hours.

Table C-11 Off-peak and on-peak, average day-ahead and real-time LMP (Dollars per MWh): 2012

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$27.88	$38.46	1.38	$27.29	$39.83	1.46	(2.1%)	3.6%	5.8%
Median	$27.15	$34.71	1.28	$26.18	$33.13	1.27	(3.6%)	(4.5%)	(1.0%)
Standard deviation	$7.66	$15.86	2.07	$12.74	$25.47	2.00	66.4%	60.6%	(3.5%)

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): 2012

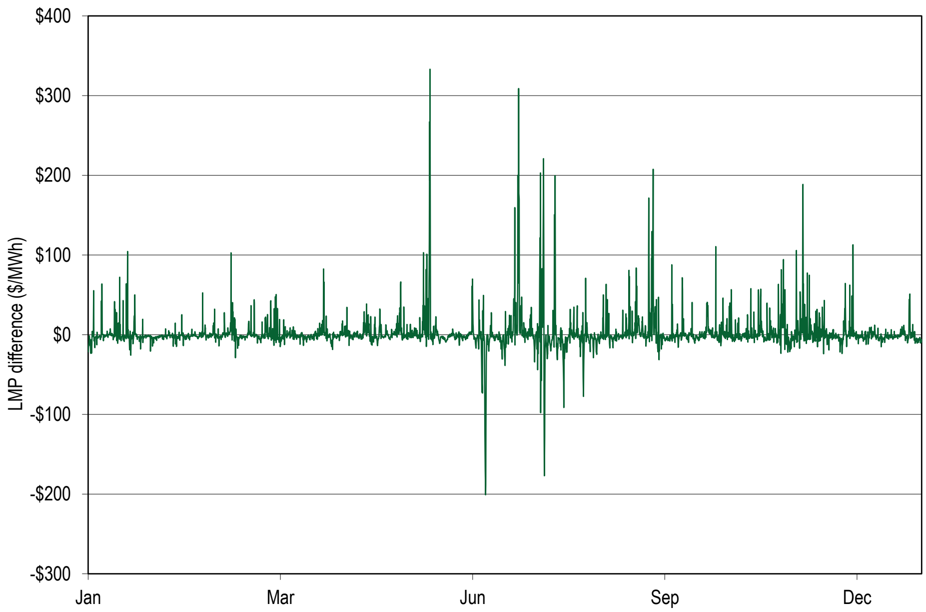
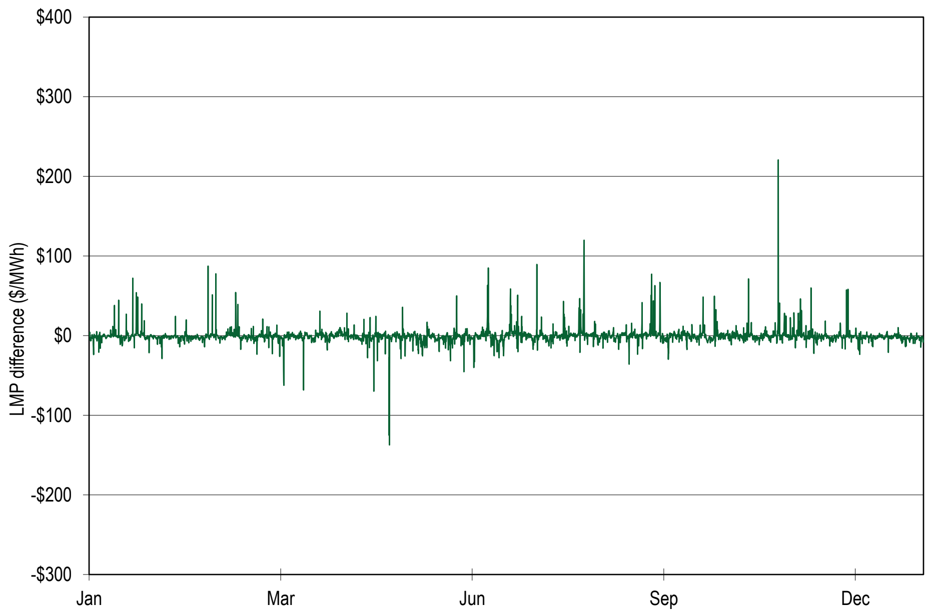


Figure C-2 Hourly real-time average LMP minus day-ahead average LMP (Off-peak hours): 2012



On-Peak and Off-Peak, Zonal, Day-Ahead and Real-Time, Average LMP

Table C-12 and Table C-13 show the on-peak and off-peak, average LMP for each zone in the Day-Ahead and Real-Time Energy Markets in 2011 and 2012.[8]

Table C-12 On-peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): 2011 and 2012

	2011				2012			
	Day Ahead	Real Time	Difference	Difference as Percent Real Time	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$57.01	$57.22	$0.21	0.37%	$40.68	$40.98	$0.30	0.73%
AEP	$45.90	$45.70	($0.20)	(0.45%)	$36.32	$37.59	$1.27	3.38%
AP	$50.60	$50.85	$0.24	0.48%	$38.20	$39.51	$1.31	3.32%
ATSI	$46.98	$46.85	($0.14)	(0.29%)	$37.19	$38.93	$1.74	4.48%
BGE	$58.02	$59.24	$1.22	2.06%	$43.66	$45.16	$1.50	3.32%
ComEd	$41.48	$41.42	($0.06)	(0.14%)	$34.22	$36.13	$1.92	5.31%
DAY	$45.93	$46.16	$0.23	0.50%	$37.14	$38.43	$1.29	3.35%
DEOK	NA	NA	NA	NA	$35.47	$36.60	$1.13	3.09%
DLCO	$46.09	$46.50	$0.41	0.88%	$36.81	$37.97	$1.16	3.06%
Dominion	$53.87	$54.63	$0.76	1.39%	$40.17	$41.65	$1.47	3.54%
DPL	$56.88	$56.84	($0.04)	(0.06%)	$42.80	$43.49	$0.69	1.59%
JCPL	$56.40	$57.51	$1.12	1.94%	$40.47	$41.00	$0.54	1.31%
Met-Ed	$54.32	$55.19	$0.87	1.58%	$39.95	$41.31	$1.36	3.30%
PECO	$56.30	$55.88	($0.42)	(0.75%)	$40.34	$41.14	$0.80	1.95%
PENELEC	$50.44	$51.17	$0.73	1.43%	$39.14	$40.27	$1.13	2.81%
Pepco	$56.45	$56.47	$0.02	0.03%	$42.60	$44.19	$1.59	3.60%
PPL	$54.17	$55.48	$1.31	2.37%	$39.14	$40.24	$1.09	2.72%
PSEG	$57.41	$58.27	$0.87	1.49%	$41.04	$41.91	$0.86	2.06%
RECO	$54.22	$52.93	($1.30)	(2.45%)	$40.07	$41.35	$1.28	3.09%

Table C-13 Off-peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): 2011 and 2012

	2011				2012			
	Day Ahead	Real Time	Difference	Difference as Percent Real Time	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$39.88	$39.13	($0.76)	(1.93%)	$28.88	$28.32	($0.56)	(1.98%)
AEP	$33.58	$33.23	($0.35)	(1.06%)	$27.23	$26.60	($0.64)	(2.39%)
AP	$36.30	$35.99	($0.32)	(0.89%)	$28.16	$27.51	($0.65)	(2.36%)
ATSI	$32.71	$32.65	($0.06)	(0.19%)	$27.70	$27.12	($0.58)	(2.15%)
BGE	$40.51	$40.27	($0.23)	(0.58%)	$31.05	$30.34	($0.72)	(2.36%)
ComEd	$26.46	$26.22	($0.24)	(0.91%)	$24.10	$23.29	($0.81)	(3.50%)
DAY	$33.51	$33.17	($0.34)	(1.02%)	$27.73	$27.07	($0.66)	(2.43%)
DEOK	NA	NA	NA	NA	$26.63	$25.98	($0.65)	(2.51%)
DLCO	$32.61	$32.43	($0.19)	(0.57%)	$26.96	$26.30	($0.66)	(2.52%)
Dominion	$39.14	$39.19	$0.05	0.13%	$29.37	$28.66	($0.71)	(2.46%)
DPL	$40.12	$39.04	($1.08)	(2.77%)	$29.83	$29.78	($0.05)	(0.16%)
JCPL	$39.91	$39.05	($0.85)	(2.19%)	$28.84	$28.04	($0.80)	(2.86%)
Met-Ed	$38.40	$37.66	($0.75)	(1.98%)	$28.24	$27.59	($0.65)	(2.35%)
PECO	$39.29	$38.44	($0.86)	(2.23%)	$28.53	$27.96	($0.57)	(2.05%)
PENELEC	$36.12	$35.79	($0.33)	(0.92%)	$28.45	$27.62	($0.83)	(3.00%)
Pepco	$39.85	$39.38	($0.48)	(1.21%)	$30.37	$29.50	($0.86)	(2.93%)
PPL	$38.28	$37.43	($0.85)	(2.26%)	$28.02	$27.47	($0.56)	(2.04%)
PSEG	$40.39	$39.36	($1.03)	(2.62%)	$29.30	$28.61	($0.69)	(2.41%)
RECO	$38.46	$36.74	($1.72)	(4.68%)	$28.88	$28.30	($0.58)	(2.06%)

8 Tables C-12 and C-13 in the *2011 State of the Market Report for PJM* incorrectly reported the LMP for the zones. The tables now show the correct LMP for each zone in 2011.

PJM Day-Ahead and Real-Time, Average LMP during Constrained Hours

Table C-14 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets and the total number of hours in each month for 2012.

Table C-14 PJM day-ahead and real-time, market-constrained hours: 2012

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	537	744
Feb	696	633	696
Mar	743	661	743
Apr	720	669	720
May	744	632	744
Jun	720	505	720
Jul	744	676	744
Aug	744	630	744
Sep	720	649	720
Oct	744	724	744
Nov	721	663	721
Dec	744	625	744
Avg	732	634	732

Table C-15 shows PJM average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets.

Table C-15 PJM average LMP during constrained and unconstrained hours (Dollars per MWh): 2012

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$0.00	$32.79	NA	$25.15	$34.35	36.6%
Median	$0.00	$30.89	NA	$26.45	$30.13	13.9%
Standard deviation	$0.00	$13.27	NA	$12.08	$21.44	77.5%

LMP by Zone and by Jurisdiction

Zonal Real-Time, Average LMP

Table C-16 Zonal real-time, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AECO	$47.56	$34.20	($13.35)	(28.1%)
AEP	$39.04	$31.70	($7.33)	(18.8%)
AP	$42.91	$33.08	($9.82)	(22.9%)
ATSI	$39.24	$32.61	($6.63)	(16.9%)
BGE	$49.11	$37.22	($11.88)	(24.2%)
ComEd	$33.30	$29.25	($4.05)	(12.2%)
DAY	$39.22	$32.35	($6.87)	(17.5%)
DEOK	NA	$30.91	NA	NA
DLCO	$38.98	$31.72	($7.26)	(18.6%)
Dominion	$46.38	$34.69	($11.69)	(25.2%)
DPL	$47.33	$36.15	($11.18)	(23.6%)
JCPL	$47.65	$34.06	($13.59)	(28.5%)
Met-Ed	$45.82	$33.96	($11.86)	(25.9%)
PECO	$46.56	$34.08	($12.48)	(26.8%)
PENELEC	$42.95	$33.50	($9.46)	(22.0%)
Pepco	$47.34	$36.33	($11.01)	(23.3%)
PPL	$45.84	$33.40	($12.44)	(27.1%)
PSEG	$48.17	$34.79	($13.38)	(27.8%)
RECO	$44.28	$34.36	($9.92)	(22.4%)
PJM	$42.84	$33.11	($9.73)	(22.7%)

Real-Time, Average LMP by Jurisdiction

Table C-17 Jurisdiction real-time, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
Delaware	$46.61	$34.50	($12.11)	(26.0%)
Illinois	$33.30	$29.25	($4.05)	(12.2%)
Indiana	$38.45	$31.56	($6.89)	(17.9%)
Kentucky	$38.39	$31.40	($6.99)	(18.2%)
Maryland	$48.06	$36.64	($11.42)	(23.8%)
Michigan	$39.30	$32.00	($7.30)	(18.6%)
New Jersey	$47.88	$34.50	($13.38)	(28.0%)
North Carolina	$45.23	$34.26	($10.97)	(24.3%)
Ohio	$39.38	$32.02	($7.36)	(18.7%)
Pennsylvania	$44.48	$33.39	($11.09)	(24.9%)
Tennessee	$38.35	$31.20	($7.16)	(18.7%)
Virginia	$45.36	$34.39	($10.97)	(24.2%)
West Virginia	$39.72	$31.62	($8.09)	(20.4%)
District of Columbia	$47.41	$36.92	($10.49)	(22.1%)

Hub Real-Time, Average LMP

Table C-18 Hub real-time, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AEP Gen Hub	$37.08	$30.46	($6.62)	(17.9%)
AEP-DAY Hub	$38.55	$31.55	($7.00)	(18.2%)
ATSI Gen Hub	$38.87	$32.19	($6.68)	(17.2%)
Chicago Gen Hub	$32.25	$28.28	($3.97)	(12.3%)
Chicago Hub	$33.48	$29.43	($4.05)	(12.1%)
Dominion Hub	$45.84	$34.19	($11.65)	(25.4%)
Eastern Hub	$47.71	$36.55	($11.16)	(23.4%)
N Illinois Hub	$33.07	$28.95	($4.12)	(12.5%)
New Jersey Hub	$47.88	$34.45	($13.43)	(28.1%)
Ohio Hub	$38.58	$31.66	($6.93)	(18.0%)
West Interface Hub	$40.57	$32.50	($8.07)	(19.9%)
Western Hub	$43.56	$33.90	($9.66)	(22.2%)

Zonal Real-Time, Load-Weighted, Average LMP

Table C-19 Zonal real-time, load-weighted, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AECO	$53.11	$37.55	($15.57)	(29.3%)
AEP	$40.92	$33.15	($7.77)	(19.0%)
AP	$45.49	$34.86	($10.63)	(23.4%)
ATSI	$42.09	$34.42	($7.67)	(18.2%)
BGE	$54.27	$40.02	($14.25)	(26.3%)
ComEd	$36.20	$31.76	($4.44)	(12.3%)
DAY	$41.78	$34.25	($7.54)	(18.0%)
DEOK	NA	$32.67	NA	NA
DLCO	$41.31	$33.53	($7.78)	(18.8%)
Dominion	$50.59	$37.28	($13.31)	(26.3%)
DPL	$52.20	$39.53	($12.67)	(24.3%)
JCPL	$53.48	$37.34	($16.14)	(30.2%)
Met-Ed	$49.51	$36.30	($13.21)	(26.7%)
PECO	$50.83	$36.78	($14.05)	(27.6%)
PENELEC	$45.12	$35.10	($10.02)	(22.2%)
Pepco	$51.84	$39.08	($12.77)	(24.6%)
PPL	$49.31	$35.44	($13.87)	(28.1%)
PSEG	$52.68	$37.48	($15.20)	(28.9%)
RECO	$49.66	$37.80	($11.86)	(23.9%)
PJM	$45.94	$35.23	($10.71)	(23.3%)

Real-Time, Load-Weighted, Average LMP by Jurisdiction

Table C-20 Jurisdiction real-time, load-weighted, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
Delaware	$51.13	$37.47	($13.66)	(26.7%)
Illinois	$36.20	$31.76	($4.44)	(12.3%)
Indiana	$40.12	$32.96	($7.15)	(17.8%)
Kentucky	$40.41	$32.75	($7.67)	(19.0%)
Maryland	$52.98	$39.53	($13.46)	(25.4%)
Michigan	$41.60	$34.08	($7.52)	(18.1%)
New Jersey	$52.91	$37.45	($15.46)	(29.2%)
North Carolina	$49.20	$36.54	($12.66)	(25.7%)
Ohio	$41.54	$33.70	($7.85)	(18.9%)
Pennsylvania	$47.65	$35.46	($12.19)	(25.6%)
Tennessee	$40.27	$32.58	($7.69)	(19.1%)
Virginia	$49.22	$36.82	($12.39)	(25.2%)
West Virginia	$41.56	$32.98	($8.58)	(20.6%)
District of Columbia	$50.88	$39.33	($11.56)	(22.7%)

Zonal Day-Ahead, Average LMP

Table C-21 Zonal day-ahead, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AECO	$47.86	$34.36	($13.50)	(28.2%)
AEP	$39.32	$31.45	($7.87)	(20.0%)
AP	$42.96	$32.82	($10.14)	(23.6%)
ATSI	$39.34	$32.11	($7.23)	(18.4%)
BGE	$48.66	$36.91	($11.75)	(24.2%)
ComEd	$33.46	$28.80	($4.66)	(13.9%)
DAY	$39.29	$32.10	($7.19)	(18.3%)
DEOK	NA	$30.73	NA	NA
DLCO	$38.89	$31.53	($7.36)	(18.9%)
Dominion	$46.00	$34.39	($11.62)	(25.2%)
DPL	$47.93	$35.86	($12.07)	(25.2%)
JCPL	$47.59	$34.24	($13.35)	(28.0%)
Met-Ed	$45.82	$33.68	($12.14)	(26.5%)
PECO	$47.21	$34.02	($13.20)	(28.0%)
PENELEC	$42.79	$33.41	($9.37)	(21.9%)
Pepco	$47.58	$36.05	($11.53)	(24.2%)
PPL	$45.68	$33.19	($12.49)	(27.3%)
PSEG	$48.32	$34.76	($13.56)	(28.1%)
RECO	$45.80	$34.08	($11.72)	(25.6%)
PJM	$42.52	$32.79	($9.73)	(22.9%)

Day-Ahead, Average LMP by Jurisdiction

Table C-22 Jurisdiction day-ahead, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
Delaware	$47.10	$34.42	($12.68)	(26.9%)
Illinois	$33.46	$28.80	($4.66)	(13.9%)
Indiana	$38.51	$30.96	($7.56)	(19.6%)
Kentucky	$38.50	$31.22	($7.28)	(18.9%)
Maryland	$48.17	$36.57	($11.60)	(24.1%)
Michigan	$39.48	$31.30	($8.18)	(20.7%)
New Jersey	$48.01	$34.54	($13.47)	(28.1%)
North Carolina	$44.86	$33.89	($10.97)	(24.4%)
Ohio	$39.36	$31.50	($7.85)	(20.0%)
Pennsylvania	$44.64	$33.25	($11.39)	(25.5%)
Tennessee	$38.61	$30.71	($7.90)	(20.5%)
Virginia	$45.23	$34.08	($11.15)	(24.7%)
West Virginia	$40.27	$31.49	($8.78)	(21.8%)
District of Columbia	$47.59	$36.43	($11.16)	(23.5%)

Zonal Day-Ahead, Load-Weighted Average LMP

Table C-23 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AECO	$53.09	$37.36	($15.74)	(29.6%)
AEP	$41.12	$32.71	($8.41)	(20.5%)
AP	$45.10	$34.29	($10.81)	(24.0%)
ATSI	$41.89	$33.55	($8.34)	(19.9%)
BGE	$53.21	$39.55	($13.66)	(25.7%)
ComEd	$35.72	$30.72	($4.99)	(14.0%)
DAY	$41.54	$33.76	($7.78)	(18.7%)
DEOK	NA	$32.18	NA	NA
DLCO	$40.98	$33.05	($7.93)	(19.4%)
Dominion	$49.78	$36.56	($13.22)	(26.6%)
DPL	$52.62	$38.91	($13.71)	(26.1%)
JCPL	$52.22	$37.03	($15.19)	(29.1%)
Met-Ed	$48.62	$35.44	($13.18)	(27.1%)
PECO	$51.11	$36.40	($14.70)	(28.8%)
PENELEC	$44.35	$34.69	($9.66)	(21.8%)
Pepco	$51.03	$38.26	($12.77)	(25.0%)
PPL	$48.69	$34.82	($13.87)	(28.5%)
PSEG	$52.23	$37.25	($14.98)	(28.7%)
RECO	$49.96	$36.91	($13.05)	(26.1%)
PJM	$45.19	$34.55	($10.64)	(23.5%)

Day-Ahead, Load-Weighted, Average LMP by Jurisdiction

Table C-24 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
Delaware	$51.46	$37.17	($14.29)	(27.8%)
Illinois	$35.72	$30.72	($4.99)	(14.0%)
Indiana	$40.15	$32.21	($7.95)	(19.8%)
Kentucky	$40.41	$32.41	($8.00)	(19.8%)
Maryland	$52.23	$39.02	($13.22)	(25.3%)
Michigan	$41.37	$32.87	($8.49)	(20.5%)
New Jersey	$52.29	$37.19	($15.10)	(28.9%)
North Carolina	$48.74	$36.03	($12.71)	(26.1%)
Ohio	$41.65	$32.90	($8.75)	(21.0%)
Pennsylvania	$47.27	$34.93	($12.33)	(26.1%)
Tennessee	$40.58	$31.75	($8.83)	(21.8%)
Virginia	$48.65	$36.07	($12.58)	(25.9%)
West Virginia	$42.07	$32.75	($9.32)	(22.2%)
District of Columbia	$50.57	$38.58	($11.99)	(23.7%)

Zonal Price Differences

Table C-25 Zonal day-ahead and real-time average LMP (Dollars per MWh): 2012

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$34.36	$34.20	($0.16)	(0.5%)
AEP	$31.45	$31.70	$0.25	0.8%
AP	$32.82	$33.08	$0.26	0.8%
ATSI	$32.11	$32.61	$0.50	1.5%
BGE	$36.91	$37.22	$0.31	0.8%
ComEd	$28.80	$29.25	$0.45	1.6%
DAY	$32.10	$32.35	$0.25	0.8%
DEOK	$30.73	$30.91	$0.18	0.6%
DLCO	$31.53	$31.72	$0.18	0.6%
Dominion	$34.39	$34.69	$0.31	0.9%
DPL	$35.86	$36.15	$0.29	0.8%
JCPL	$34.24	$34.06	($0.18)	(0.5%)
Met-Ed	$33.68	$33.96	$0.29	0.8%
PECO	$34.02	$34.08	$0.07	0.2%
PENELEC	$33.41	$33.50	$0.08	0.2%
Pepco	$36.05	$36.33	$0.28	0.8%
PPL	$33.19	$33.40	$0.21	0.6%
PSEG	$34.76	$34.79	$0.03	0.1%
RECO	$34.08	$34.36	$0.28	0.8%
PJM	$32.79	$33.11	$0.32	1.0%

Jurisdictional Price Differences

Table C-26 Jurisdiction day-ahead and real-time average LMP (Dollars per MWh): 2012

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$34.42	$34.50	$0.07	0.2%
Illinois	$28.80	$29.25	$0.45	1.6%
Indiana	$30.96	$31.56	$0.60	2.0%
Kentucky	$31.22	$31.40	$0.18	0.6%
Maryland	$36.57	$36.64	$0.07	0.2%
Michigan	$31.30	$32.00	$0.71	2.3%
New Jersey	$34.54	$34.50	($0.05)	(0.1%)
North Carolina	$33.89	$34.26	$0.37	1.1%
Ohio	$31.50	$32.02	$0.52	1.6%
Pennsylvania	$33.25	$33.39	$0.14	0.4%
Tennessee	$30.71	$31.20	$0.49	1.6%
Virginia	$34.08	$34.39	$0.31	0.9%
West Virginia	$31.49	$31.62	$0.13	0.4%
District of Columbia	$36.43	$36.92	$0.49	1.3%

Offer-Capped Units

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. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets.

PJM has clear rules limiting the exercise of local market power.[9] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[10] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

Levels of offer capping have generally been low and stable over the last five years. Table C-27 through Table C-30 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.

9 See OA Schedule 1, § 6.4.2

10 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."

Table C-27 Average day-ahead, offer-capped units: 2008 to 2012

	2008		2009		2010		2011		2012	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.5	0.0%	0.7	0.1%	0.6	0.1%	0.1	0.0%	0.0	0.0%
Feb	0.2	0.0%	0.3	0.0%	0.6	0.1%	0.0	0.0%	0.8	0.1%
Mar	0.0	0.0%	0.6	0.1%	0.3	0.0%	0.1	0.0%	0.2	0.0%
Apr	0.2	0.0%	0.0	0.0%	0.8	0.1%	0.3	0.0%	0.0	0.0%
May	0.6	0.1%	0.1	0.0%	1.2	0.1%	0.1	0.0%	0.8	0.1%
Jun	1.5	0.1%	0.3	0.0%	2.0	0.2%	0.0	0.0%	0.1	0.0%
Jul	1.7	0.2%	0.0	0.0%	2.8	0.3%	0.2	0.0%	0.2	0.0%
Aug	0.2	0.0%	0.4	0.0%	0.5	0.0%	0.3	0.0%	0.2	0.0%
Sep	0.4	0.0%	0.2	0.0%	0.5	0.0%	0.3	0.0%	3.0	0.2%
Oct	0.4	0.0%	0.1	0.0%	0.3	0.0%	0.0	0.0%	5.9	0.5%
Nov	0.5	0.0%	0.0	0.0%	0.3	0.0%	0.2	0.0%	5.4	0.4%
Dec	1.3	0.1%	0.3	0.0%	0.0	0.0%	0.0	0.0%	9.6	0.8%

Table C-28 Average day-ahead, offer-capped MW: 2008 to 2012

	2008		2009		2010		2011		2012	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	16	0.0%	98	0.1%	50	0.1%	9	0.0%	0	0.0%
Feb	11	0.0%	30	0.0%	29	0.0%	0	0.0%	515	0.5%
Mar	2	0.0%	47	0.1%	17	0.0%	13	0.0%	77	0.1%
Apr	31	0.0%	0	0.0%	98	0.1%	33	0.0%	1	0.0%
May	15	0.0%	9	0.0%	117	0.1%	14	0.0%	62	0.1%
Jun	91	0.1%	42	0.0%	129	0.1%	4	0.0%	4	0.0%
Jul	110	0.1%	0	0.0%	143	0.1%	20	0.0%	15	0.0%
Aug	35	0.0%	35	0.0%	61	0.1%	45	0.0%	30	0.0%
Sep	66	0.1%	10	0.0%	34	0.0%	38	0.0%	548	0.6%
Oct	39	0.0%	3	0.0%	26	0.0%	1	0.0%	847	1.0%
Nov	47	0.1%	0	0.0%	23	0.0%	23	0.0%	943	1.1%
Dec	187	0.2%	29	0.0%	0	0.0%	0	0.0%	1568	1.7%

Table C-29 Average real-time, offer-capped units: 2008 to 2012

	2008		2009		2010		2011		2012	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	3.1	0.3%	2.4	0.2%	2.3	0.2%	2.8	0.3%	3.0	0.3%
Feb	2.6	0.3%	1.1	0.1%	1.9	0.2%	2.3	0.2%	6.5	0.5%
Mar	2.7	0.3%	1.8	0.2%	2.5	0.2%	1.6	0.1%	5.7	0.5%
Apr	3.1	0.3%	1.8	0.2%	3.2	0.3%	2.8	0.3%	4.0	0.3%
May	2.1	0.2%	1.0	0.1%	4.5	0.4%	2.8	0.3%	4.5	0.4%
Jun	8.7	0.8%	1.3	0.1%	7.1	0.7%	4.3	0.4%	3.3	0.3%
Jul	5.7	0.6%	1.1	0.1%	9.3	0.9%	8.0	0.7%	5.6	0.5%
Aug	2.0	0.2%	3.0	0.3%	5.8	0.5%	3.2	0.3%	3.4	0.3%
Sep	4.8	0.5%	1.6	0.1%	6.2	0.6%	6.4	0.6%	5.2	0.4%
Oct	2.5	0.2%	1.2	0.1%	3.5	0.3%	4.3	0.4%	6.2	0.5%
Nov	2.2	0.2%	0.6	0.1%	3.1	0.3%	4.1	0.4%	6.3	0.5%
Dec	2.5	0.2%	1.3	0.1%	6.3	0.6%	4.7	0.4%	10.7	0.9%

Table C-30 Average real-time, offer-capped MW: 2008 to 2012

	2008		2009		2010		2011		2012	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	99	0.1%	158	0.2%	124	0.1%	197	0.2%	186	0.2%
Feb	92	0.1%	92	0.1%	117	0.1%	125	0.2%	1435	1.6%
Mar	117	0.2%	147	0.2%	216	0.3%	167	0.2%	812	1.0%
Apr	125	0.2%	151	0.2%	251	0.4%	267	0.4%	412	0.5%
May	59	0.1%	64	0.1%	337	0.5%	291	0.4%	400	0.5%
Jun	415	0.5%	103	0.1%	382	0.4%	330	0.4%	321	0.3%
Jul	202	0.2%	74	0.1%	473	0.5%	436	0.4%	451	0.4%
Aug	99	0.1%	137	0.2%	253	0.3%	245	0.3%	361	0.4%
Sep	182	0.2%	95	0.1%	378	0.5%	436	0.5%	705	0.8%
Oct	177	0.3%	105	0.2%	345	0.5%	319	0.4%	798	1.0%
Nov	157	0.2%	60	0.1%	382	0.5%	324	0.4%	955	1.1%
Dec	211	0.3%	128	0.2%	538	0.6%	330	0.4%	1546	1.8%

In order to help understand the frequency of offer capping in more detail, Table C-31 through Table C-35 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the years 2008 through 2012.

Table C-31 Offer-capped unit statistics: 2008

	2008 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	1	4
80% and < 90%	0	0	1	0	4	10
75% and < 80%	0	0	5	4	4	11
70% and < 75%	1	0	1	2	4	9
60% and < 70%	1	0	0	4	4	30
50% and < 60%	0	0	2	3	3	20
25% and < 50%	0	5	10	11	10	57
10% and < 25%	1	0	1	0	6	48

Table C-32 Offer-capped unit statistics: 2009

	2009 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	1	6
80% and < 90%	0	0	0	1	2	13
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	1	1	9
60% and < 70%	0	0	0	0	1	21
50% and < 60%	0	0	0	0	1	19
25% and < 50%	0	1	1	2	3	56
10% and < 25%	1	0	0	0	6	53

Table C-33 Offer-capped unit statistics: 2010

	2010 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	1	13
80% and < 90%	0	2	1	7	8	13
75% and < 80%	0	0	0	0	3	7
70% and < 75%	3	0	0	0	4	13
60% and < 70%	0	1	1	1	0	34
50% and < 60%	1	0	0	5	0	22
25% and < 50%	4	2	4	9	17	41
10% and < 25%	2	0	0	4	2	37

Table C-34 Offer-capped unit statistics: 2011

	2011 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	6	9	4
80% and < 90%	0	0	1	2	5	9
75% and < 80%	0	0	0	0	3	3
70% and < 75%	0	0	0	0	0	10
60% and < 70%	0	1	0	1	1	20
50% and < 60%	0	0	0	2	13	23
25% and < 50%	2	0	0	5	19	70
10% and < 25%	9	2	0	0	2	49

Table C-35 Offer-capped unit statistics: 2012

	2012 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	2	0	1	1	1
80% and < 90%	0	1	0	0	2	4
75% and < 80%	0	0	0	0	1	2
70% and < 75%	0	0	0	0	1	2
60% and < 70%	1	0	0	1	1	8
50% and < 60%	7	0	1	0	1	10
25% and < 50%	5	1	1	2	8	49
10% and < 25%	6	0	0	3	13	58

Local Energy Market Structure: TPS Results

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint.

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, 2012, through December 31, 2012. 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.

This appendix provides data on the TPS tests that were applied in PJM control zones that had congestion from one or more constraints for 100 or more hours. In 2012, the AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, PECO, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for 2012, actual competitive conditions associated with each of these frequently binding constraints were analyzed for the Real Time Energy Market.[1] The AECO, AEP, DAY, JCPL, Met-Ed, PPL, PENELEC, and RECO Control Zones were not affected by constraints binding for 100 or more hours. Information is provided, by qualifying zone, for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping and the number of tests that did result in offer capping.[2] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

AP Control Zone Results

In 2012, there was one constraint that occurred for more than 100 hours in the AP Control Zone. Table D-1 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.

Table D-2 shows the total tests applied for the constraint in the AP Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results

Table D-1 Three pivotal supplier test details for constraints located in the AP Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Garretts Run - Kiski Valley	Peak	20	36	2	0	2
	Off Peak	9	18	2	0	2

Table D-2 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AP Control Zone: 2012

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
Garretts Run - Kiski Valley	Peak	2,405	10	0%	0	0%	0%
	Off Peak	533	2	0%	0	0%	0%

1 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.
2 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-2 shows that none of the tests applied to the 'Garretts Run - Kiski Valley' constraint in the AP Zone resulted in offer capping.

ATSI Control Zone Results

In 2012, there was only one constraint in the ATSI Control Zone that occurred for more than 100 hours. Table D-3 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. Table D-3 shows that on an average, there was only one owner with available supply on peak and one owner off peak for the Lemoyne – Bowling Green line. The three pivotal supplier test results reflect this, as all tests were failed.

Table D-4 shows the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and those tests that did result in offer capping for the Lemoyne – Bowling Green line in the ATSI zone. None of the 569 tests applied to offline, uncommitted units that were eligible for offer capping on peak. None of the tests resulted in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

Table D-3 Three pivotal supplier test details for constraints located in the ATSI Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Lemoyne - Bowling Green	Peak	10	6	1	0	1
	Off Peak	4	4	1	0	1

Table D-4 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ATSI Control Zone: 2012

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
Lemoyne - Bowling Green	Peak	569	0	0%	0	0%	0%
	Off Peak	4	0	0%	0	0%	0%

BGE Control Zone Results

In 2012, there were three constraints that occurred for more than 100 hours in the BGE Control Zone. Table D-5 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 owner passing and failing. Table D-5 shows that for two of the three constraints, there were ten owners, on an average, with available supply to relieve the constraint, both on peak and off peak.

Table D-6 shows the total tests applied for the three constraints in the BGE Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-6 shows that one percent or fewer of the tests applied to the three constraints in the BGE zone could have resulted in offer capping and that one percent or fewer of their tests resulted in offer capping.

Table D-5 Three pivotal supplier test details for constraints located in the BGE Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Conastone - Otter	Peak	71	127	11	4	7
	Off Peak	58	106	10	3	7
Graceton - Raphael Road	Peak	59	110	10	3	7
	Off Peak	52	94	10	3	7
Northwest	Peak	64	100	10	2	8
	Off Peak	67	101	10	2	8

Table D-6 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the BGE Control Zone: 2012

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
Conastone - Otter	Peak	2,490	21	1%	2	0%	10%
	Off Peak	2,625	18	1%	2	0%	11%
Graceton - Raphael Road	Peak	9,521	86	1%	11	0%	13%
	Off Peak	10,997	65	1%	5	0%	8%
Northwest	Peak	9,946	68	1%	8	0%	12%
	Off Peak	4,484	35	1%	2	0%	6%

ComEd Control Zone Results

In 2012, there were four constraints that occurred for more than 100 hours in the ComEd Control Zone. Table D-7 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 owner passing and failing. The average number of owners with available supply was three or less for all four constraints.

Table D-8 shows the total tests applied for the four constraints in the ComEd zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

Table D-7 Three pivotal supplier test details for constraints located in the ComEd Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Belvidere - Woodstock	Peak	12	10	2	0	2
	Off Peak	10	8	2	0	2
Dixon - Stillman Valley	Peak	23	18	2	0	2
	Off Peak	16	10	2	0	2
Mazon - Mazon	Peak	10	16	2	0	2
	Off Peak	8	15	2	0	2
Nelson - Cordova	Peak	39	34	3	0	3
	Off Peak	29	28	2	0	2

Table D-8 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ComEd Control Zone: 2012

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
Belvidere - Woodstock	Peak	8,229	2	0%	1	0%	50%
	Off Peak	8,401	3	0%	0	0%	0%
Dixon - Stillman Valley	Peak	1,871	2	0%	2	0%	100%
	Off Peak	716	0	0%	0	0%	0%
Mazon - Mazon	Peak	1,008	0	0%	0	0%	0%
	Off Peak	352	0	0%	0	0%	0%
Nelson - Cordova	Peak	1,222	4	0%	0	0%	0%
	Off Peak	1,209	0	0%	0	0%	0%

DEOK Control Zone Results

In 2012, there was only one constraint that occurred for more than 100 hours in the DEOK Control Zone. Table D-9 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 owner passing and failing.

Table D-10 shows the total tests applied for the 'Todd Hunter-Trenton' constraint in the DEOK zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. None of the tests that were applied to the constraint resulted in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

Table D-9 Three pivotal supplier test details for constraints located in the DEOK Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Todd Hunter - Trenton	Peak	19	10	1	0	1
	Off Peak	14	10	1	0	1

Table D-10 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DEOK Control Zone: 2012

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
Todd Hunter - Trenton	Peak	1,579	0	0%	0	0%	0%
	Off Peak	985	0	0%	0	0%	0%

DLCO Control Zone Results

In 2012, there was only one constraint that occurred for more than 100 hours in the DLCO Control Zone. Table D-11 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 owner passing and failing. The average number of owners with available supply was one on peak and two off peak for the 'Brunot Island – Montour' constraint.

Table D-12 shows the total tests applied for the 'Brunot Island – Montour' constraint in the DLCO zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-12 shows that only 4 of the 8,180 applied tests could have resulted in offer capping and none of those tests resulted in offer capping.

Table D-11 Three pivotal supplier test details for constraints located in the DLCO Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brunot Island - Montour	Peak	19	35	1	0	1
	Off Peak	25	33	2	0	2

Table D-12 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DLCO Control Zone: 2012

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
Brunot Island - Montour	Peak	5,063	1	0%	0	0%	0%
	Off Peak	3,117	3	0%	0	0%	0%

Dominion Control Zone Results

In 2012, there were two constraints that occurred for more than 100 hours in the Dominion Control Zone. Table D-13 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 owner passing and failing. The average number of owners with available supply was three or fewer for both the constraints.

Table D-14 shows the total tests applied for the five constraints in the Dominion zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-14 shows that one percent or fewer of the tests applied to the two constraints in the Dominion Zone could have resulted in offer capping.

Table D-13 Three pivotal supplier test details for constraints located in the Dominion Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	9	10	1	0	1
	Off Peak	11	10	1	0	1
Clover	Peak	93	155	2	0	2
	Off Peak	92	158	3	0	2

Table D-14 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Dominion Control Zone: 2012

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
Beechwood - Kerr Dam	Peak	2,462	0	0%	0	0%	0%
	Off Peak	447	0	0%	0	0%	0%
Clover	Peak	12,359	94	1%	38	0%	40%
	Off Peak	4,887	43	1%	11	0%	26%

DPL Control Zone Results

In 2012, there were two constraints that occurred for more than 100 hours in the DPL Control Zone. Table D-15 shows the average constraint relief required on each 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. The average number of owners with available supply was one on peak and off peak for both of the constraints.

Table D-16 shows the total tests applied for the two constraints in the DPL zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-16 shows that only 4 of the 7,620 applied tests for the 'Kenney – Stockton' constraint could have resulted in offer capping and all of those tests resulted in offer capping.

Table D-15 Three pivotal supplier test details for constraints located in the DPL Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Kenney - Stockton	Peak	42	48	1	0	1
	Off Peak	21	24	1	0	1
Mardela - Vienna	Peak	38	40	1	0	1
	Off Peak	25	27	1	0	1

Table D-16 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DPL Control Zone: 2012

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
Kenney - Stockton	Peak	4,521	3	0%	3	0%	100%
	Off Peak	3,099	1	0%	1	0%	100%
Mardela - Vienna	Peak	2,514	16	1%	12	0%	75%
	Off Peak	849	7	1%	7	1%	100%

Table D-17 Three pivotal supplier test details for constraints located in the PECO Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Emilie	Peak	57	111	1	0	1
	Off Peak	43	107	1	0	1

Table D-18 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PECO Control Zone: 2012

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
Emilie	Peak	1,366	1	0%	0	0%	0%
	Off Peak	1,140	0	0%	0	0%	0%

PECO Control Zone Results

In 2012, there was one constraint that occurred for more than 100 hours in the PECO Control Zone. Table D-17 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 owner passing and failing. For the constraint at Emilie, on an average, there was only one owner with available supply to relieve the constraint.

Table D-18 shows the total tests applied for the constraint in the PECO zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-18 shows that only one of the tests applied to the constraint in the PECO Zone could have resulted in offer capping.

Pepco Control Zone Results

In 2012, there was one constraint that occurred for more than 100 hours in the Pepco Control Zone. Table D-19 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 owner passing and failing. On an average, there was only one owner with available supply to relieve the constraint.

Table D-20 shows the total tests applied for the 'Buzzard – Ritchie' constraint in the Pepco zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-20 shows that only one of the tests applied to the constraint in the Pepco zone could have resulted in offer capping.

Table D-19 Three pivotal supplier test details for constraints located in the Pepco Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Buzzard - Ritchie	Peak	31	36	1	0	1
	Off Peak	10	34	1	0	1

Table D-20 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Pepco Control Zone: 2012

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
Buzzard - Ritchie	Peak	3,374	1	0%	1	0%	100%
	Off Peak	266	0	0%	0	0%	0%

PSEG Control Zone Results

In 2012, there were two constraints that occurred for more than 100 hours in the PSEG Control Zone. Table D-21 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 owner passing and failing. For both of the constraints, the average number of owners with available supply was three or less.

Table D-22 shows the total tests applied for the two constraints in the PSEG zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-22 shows that two percent or fewer of the tests applied to the two constraints in the PSEG zone could have resulted in offer capping. The Hillsdale – New Milford constraint had only 24 of its 5,603 applied tests that could have resulted in offer capping. Only 15 of the 5,603 applied tests did result in offer capping.

Table D-21 Three pivotal supplier test details for constraints located in the PSEG Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Hillsdale - New Milford	Peak	28	49	2	0	2
	Off Peak	26	57	2	0	2
Leonia - New Milford	Peak	35	45	3	0	3
	Off Peak	26	54	2	0	2

Table D-22 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PSEG Control Zone: 2012

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
Hillsdale - New Milford	Peak	3,172	23	1%	15	0%	65%
	Off Peak	2,431	1	0%	0	0%	0%
Leonia - New Milford	Peak	993	15	2%	12	1%	80%
	Off Peak	1,391	24	2%	24	2%	100%

Interchange Transactions

Submitting Transactions into PJM

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security constrained nodal pricing, well designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements.

In order to understand the data on imports and exports, it is important to understand the institutional details of completing import and export transactions. These include the Open Access Same-Time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out processes, and transaction curtailment rules.[1]

Real-Time Market

Market participants that wish to transact energy into, out of, or through PJM in the Real-Time Energy Market are required to make their requests to PJM via the NERC Interchange Transaction Tag (NERC Tag). PJM's Enhanced Energy Scheduler (EES) software interfaces with NERC Tags to create an interface that both PJM market participants and PJM can use to evaluate and manage external transactions that affect the PJM RTO.

All PJM interchange transactions are required to be at least 45 minutes in duration. However, PJM system operators may make adjustments that cause a transaction or interval(s) of the transaction to violate this minimum duration.

Scheduling Requirements

External offers can be made either on the basis of an individual generator (resource specific offer) or an aggregate of generation supply (aggregate offer). Schedules are submitted to PJM by submitting a valid NERC Tag.

Specific timing requirements apply for the submission of schedules. Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions. Schedules can be submitted up to 4 hours prior to the scheduled start time for transactions that are more than 24 hours in duration. For a schedule to be included in PJM's day-ahead checkout process, the NERC Tag must be approved by all entities who have approval rights, and be in a status of "Implemented", by 1400 (EPT) one day prior to start of schedule. Schedules utilizing the Real-Time with Price option, also known as dispatchable schedules, must be submitted prior to 1200 noon (EPT) the day prior to the scheduled start time. Schedules utilizing firm point-to-point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions utilizing firm point-to-point transmission submitted after 1000 (EPT) one day prior will be accommodated if practicable.

Acquiring Ramp

PJM allows market participants to reserve ramp while they complete their scheduling responsibilities. The ramp reservation is validated against the submitted NERC Tag to ensure the energy profile and path matches. Upon submission of a ramp reservation request, if PJM verifies ramp availability, the ramp reservation will move into a status of "Pending Tag" which means that it is a valid reservation that can be associated with a NERC Tag to complete the scheduling process.

Specific timing requirements apply for the submission of ramp reservations. Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions. Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration. Ramp reservations utilizing the Real-Time with Price option must be made prior to 1200 noon (EPT) the day prior to the scheduled start time. Ramp reservations expire if they are not used.

Acquiring Transmission

All external transaction requests require a confirmed transmission reservation from the PJM OASIS.[2] Due to ramp limitations, PJM may require market participants to shift their transaction requests. If the market participant shifts the request up to one hour in either direction, they are not required to purchase additional transmission. If the market participant chooses to fix a ramp violation

1 The material in this section is based in part on PJM Manual M-41: Managing Interchange. See PJM. "M-41: Managing Interchange", Revision 04 (December 3, 2012).

2 For additional details see PJM. "*PJM Regional Practices document,*" <http://oasis.pjm.com>.

by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded, and the transaction does not extend beyond one hour prior to the start, or one hour past the end time of the transmission reservation.

Transmission Products

The OASIS products available for reservation include firm, network, non-firm and spot import service. The product type designated on the OASIS reservation determines when and how the transaction can be curtailed.

- **Firm.** Transmission service that is intended to be available at all times.
- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.
- **Non-Firm.** Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point-to-point transmission service is available for periods ranging from one hour to one month.
- **Spot Import.** The spot import service is an option for non-load serving entities to offer into the PJM spot market at the interface as price takers. Prior to April 2007, PJM did not limit spot import service. Effective April 2007, the availability of spot import service was limited by the Available Transmission Capacity (ATC) on the transmission path.

Source and Sink

For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA's Interface Pricing point (SouthIMP). At the time the energy is scheduled, if the Generation Control Area (GCA) on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. The sink bus is selected by the market participant at the time the OASIS reservation is made and can be any bus, hub or aggregate in the PJM footprint where LMP is calculated.

For a real-time export energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is TVA, the sink would initially default to TVA's Interface Pricing point (SouthEXP). At the time the energy is scheduled, if the Load Control Area (LCA) on the NERC Tag represents physical flow leaving PJM at an interface other than the SouthEXP Interface, the sink would then default to that new interface. The source bus is selected by the market participant at the time the OASIS reservation is made and can be any bus, hub or aggregate in the PJM footprint where LMP is calculated.

For a real-time wheel through energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface Pricing point (SouthIMP), and the sink would initially default to NYIS's Interface Pricing point (NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Real-Time Market Schedule Submission

Market participants enter schedules in PJM by submitting a valid NERC Tag. A NERC Tag can be submitted without a ramp reservation. When EES detects a NERC Tag that has been submitted without a ramp reservation, it will create a ramp reservation which will be evaluated against ramp, and approved or denied based on available ramp room at the time the NERC Tag is submitted.

Real-Time with Price Schedule Submission

Real-Time with Price schedules, also known as dispatchable schedules, differ from other schedules. To enter a Real-Time with Price schedule, the market participant must first make a ramp reservation in EES specifying "Real-Time with Price" and must enter a price associated with each energy block. Upon submission, the Real-Time with Price request will automatically move to the "Pending Tag" status, as Real-Time with Price schedules do not hold ramp. Once the information is entered in EES, a NERC Tag must be submitted with the ramp reservation associated on the NERC Tag. Upon implementation of the NERC Tag, PJM will curtail the tag to 0 MW. During the operating day, if the dispatchable transaction is to be loaded, PJM will then reload the tag. The process of issuing curtailments and reloading the tag continues through the operating day as the economics of the system dictate.

Dynamic Schedule Requirements

An entity that owns or controls a generating resource in the PJM Region may request that all or part of the generating resource's output be removed from the PJM Region, via dynamic scheduling of the output, to a load outside the PJM Region. An entity that owns or controls a generating resource outside of the PJM Region may request that all or part of the generating resource's output be added to the PJM Region, via dynamic scheduling of the output, to a load inside the PJM Region. Due to the complexity of these arrangements, requesting entities must coordinate with PJM and complete several steps before a dynamic schedule can be implemented. The requesting entity is responsible for submitting a dynamic NERC Tag to match the scheduled output of the generating resource.

Real-Time Evaluation and Checkout

PJM conducts an hourly checkout with each adjacent balancing authority using both the electronic approval of schedules and telephone calls. Once the tag has been approved by all parties with approval rights, the tag status moves to an "Implemented" status, and the schedule is ready for the adjacent balancing authority checkout.

PJM operators must verify all requested energy schedules with PJM's neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. Both balancing authorities must enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy flows between balancing authorities.

With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests in the same way as PJM. While the NYISO also requires NERC Tags, the NYISO utilizes their Market Information System (MIS) as their primary scheduling tool. The NYISO's real-time commitment (RTC) tool evaluates all bids and offers each hour, performs a least cost economic dispatch solution, and accepts or denies individual transactions in whole or in part based on this evaluation. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour.

Real-Time with Price Evaluation and Checkout

Real-time with price schedules, also known as dispatchable schedules, are evaluated hourly to determine whether or not they will be loaded for the upcoming hour. Since real-time with price schedules do not hold ramp room, there may be times when the schedule is economic but will not be loaded because ramp is not available.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed based on economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules based on price; curtailments of transactions based on their OASIS designation as not willing to pay congestion; and self curtailments by market participant. Reliability curtailments are implemented by the balancing authorities and are termed TLRs or transmission loading relief.

Dispatchable transactions will be curtailed if the system operator does not believe that the transaction will be economic for the next hour. Not willing to pay congestion transactions will be curtailed if there is realized congestion between the designated source and sink. Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero. All self curtailments must be requested on 15 minute intervals and will be approved only if there is available ramp.

Transmission Loading Relief (TLR)

TLRs are called to control flows on transmission 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.

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or non-firm transmission. Reliability coordinators are not required to implement TLRs in order. The TLR levels are described below.[3]

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state. Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.
- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.
- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse affect on the identified transmission facility(ies) from starting.
- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using non-firm point-to-point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using non-firm point-to-point transmission service that have a greater than 5 percent effect on the facility and when there are transactions using a higher priority point-to-point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower priority non-firm point-to-point transmission to allow transactions using higher priority transmission to flow.
- **TLR Level 3b – Curtail interchange transactions using non-firm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using non-firm point-to-point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using non-firm point-to-point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.
- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using non-firm point-to-point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed under the TLR

3 Additional details regarding the TLR procedure can be found in NERC. "Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief" (October 23, 2007) (Accessed January 16, 2013) <http://www.nerc.com/files/IRO-006-4.pdf>.

3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.

- **TLR Level 5a – Reallocation of transmission service by curtailing interchange transactions using firm point-to-point transmission service on a pro rata basis to allow additional interchange transactions using firm point-to-point transmission service:** 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.
- **TLR Level 5b – Curtail transactions using firm point-to-point transmission service to mitigate an SOL or IROL violation:** 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. Unlike a TLR 5a, curtailments to transactions in a TLR 5b can occur at any time within the operating hour. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL.
- **TLR Level 6 – Emergency Procedures:** A TLR Level 6 is initiated when all interchange transactions using both non-firm and firm point-to-point transmission have been curtailed and one or more transmission facilities are above their SOL or IROL, or will exceed their SOL or IROL upon removal of a generating unit or other transmission facility. The purpose of a TLR Level 6 is to instruct balancing authorities and transmission providers to redispatch generation, reconfigure transmission or reduce load to mitigate the critical condition.

Table E-1 shows the historic number of TLRs, by level, issued by reliability coordinators in the Eastern Interconnection since 2004.

Day-Ahead Market

For Day-Ahead Market scheduling, EES serves only as an interface to the eMarket application. Day-Ahead Market transactions are evaluated in the Day-Ahead Market, and the results sent to EES. No checkout is performed on Day-Ahead Market schedules as they are considered financially binding transactions and not physical schedules.

Submitting Day-Ahead Market Schedules

Market participants can submit Day-Ahead Market schedules to the eMarket application through EES. These schedules do not require a NERC Tag, as they are not physical schedules for actual flow. Day-Ahead Market schedules require an OASIS number to be associated upon submission.4 The path is identified on the OASIS reservation. In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. "Fixed" act as a price taker, "dispatchable" set a floor or ceiling price criteria for acceptance and "up-to" set the maximum amount of congestion the market participant is willing to pay.

4 On September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additionally, effective May 15, 2012, up-to congestion transactions were required to be submitted for the PJM Day-Ahead Market evaluation in the eMarket application, and are no longer accepted through the EES application. Additional details can be found under the "Up-to Congestion" heading in *Section 4: Interchange Transactions* of this report.

Table E-1 TLRs by level and reliability coordinator: 2004 through 2012

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2004	EES	47	15	88	1	3	0	154
	FPL	0	1	0	0	0	0	1
	IMO	33	2	0	0	0	0	35
	MAIN	8	3	0	0	0	0	11
	MISO	650	210	409	9	3	0	1,281
	PJM	270	115	35	4	5	0	429
	SOCO	1	0	0	0	0	0	1
	SWPP	185	107	14	5	6	0	317
	TVA	56	17	0	0	1	0	74
	VACN	8	1	0	0	0	0	9
Total		1,258	471	546	19	18	0	2,312
2005	EES	49	10	101	6	3	1	170
	IMO	57	2	0	0	0	0	59
	MISO	776	296	200	5	14	0	1,291
	PJM	201	94	29	1	1	0	326
	SWPP	193	78	19	4	2	0	296
	TVA	172	61	12	2	3	0	250
	VACN	0	3	0	0	0	0	3
	VACS	2	2	0	1	0	0	5
Total		1,450	546	361	19	23	1	2,400
2006	EES	71	20	93	5	1	0	190
	ICTE	11	6	14	0	1	0	32
	IMO	1	0	0	0	0	0	1
	MISO	414	214	136	17	19	0	800
	ONT	27	3		0	0	0	30
	PJM	88	30	18	0	0	0	136
	SWPP	189	121	201	11	13	0	535
	TVA	90	52	31	1	2	0	176
	VACS	0	1	0	0	0	0	1
Total		891	447	493	34	36	0	1,901
2007	ICTE	95	42	139	19	10	0	305
	MISO	414	273	89	17	26	0	819
	ONT	47	4	1	0	0	0	52
	PJM	46	31	1	1	1	0	80
	SWPP	777	935	35	53	24	0	1,824
	TVA	45	40	25	2	2	0	114
	VACS	4	1	0	0	0	0	5
Total		1428	1326	290	92	63	0	3199
2008	ICTE	132	41	112	43	25	0	353
	MISO	320	235	21	8	15	0	599
	ONT	153	7	1	0	0	0	161
	PJM	55	92	2	0	1	0	150
	SWPP	687	1,077	11	59	44	0	1,878
	TVA	48	72	29	5	4	0	158
Total		1,395	1,524	176	115	89	0	3,299
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097
2010	ICTE	72	25	149	50	30	0	326
	MISO	123	93	0	15	18	0	249
	NYIS	104	0	0	0	0	0	104
	ONT	94	5	0	1	0	0	100
	PJM	65	45	0	0	0	0	110
	SWPP	244	1,049	19	63	32	0	1,407
	TVA	37	64	8	1	6	0	116
	VACS	1	1	0	0	0	0	2
Total		740	1,282	176	130	86	0	2,414
2011	ICTE	23	12	123	54	48	0	260
	MISO	92	30	1	9	9	0	141
	NYIS	161	0	0	0	0	0	161
	ONT	88	0	0	0	0	0	88
	PJM	34	28	0	0	0	0	62
	SWPP	292	298	1	25	22	0	638
	TVA	75	99	9	2	15	0	200
	VACS	9	3	0	0	0	0	12
Total		774	470	134	90	94	0	1,562
2012	ICTE	25	7	11	63	40	0	146
	MISO	75	26	0	16	42	0	159
	NYIS	60	0	0	0	0	0	60
	ONT	47	1	0	0	0	0	48
	PJM	18	19	0	0	0	0	37
	SOCO	0	1	0	0	0	0	1
	SWPP	248	165	5	78	33	0	529
	TVA	55	32	9	7	5	0	108
	VACS	6	4	0	0	0	0	10
Total		534	255	25	164	120	0	1,098

NYISO Issues

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-ISO power flows, and those price differentials.[5]

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.6 The NYISO requires hourly bids or offer prices for each export or import transaction and clears

5 See also the discussion of these issues in the 2005 State of the Market Report, *Section 4, "Interchange Transactions"* (March 8, 2006).

6 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.

its market for each hour based on hourly bids.[7] Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. The lag is a result of the Real-Time Commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no later than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of the NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single hour.

Under PJM operating practices, in the Real-Time Market, participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[8] The duration of the requested transaction can vary from 45 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, less than 1 percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission, based on whether PJM has the capability to import or export the requested MW. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating hour. Winning bidders then have 25 minutes from the time when the RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

Consolidated Edison Company (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. A common path is through Westchester County using lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM. 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. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[9] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[10] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[11] PJM continued to operate under the terms of the protocol through 2012.

7 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed January 16, 2013) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

8 See PJM. "Manual 41: Managing Interchange" (December 3, 2012) (Accessed January 16, 2013) <http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).

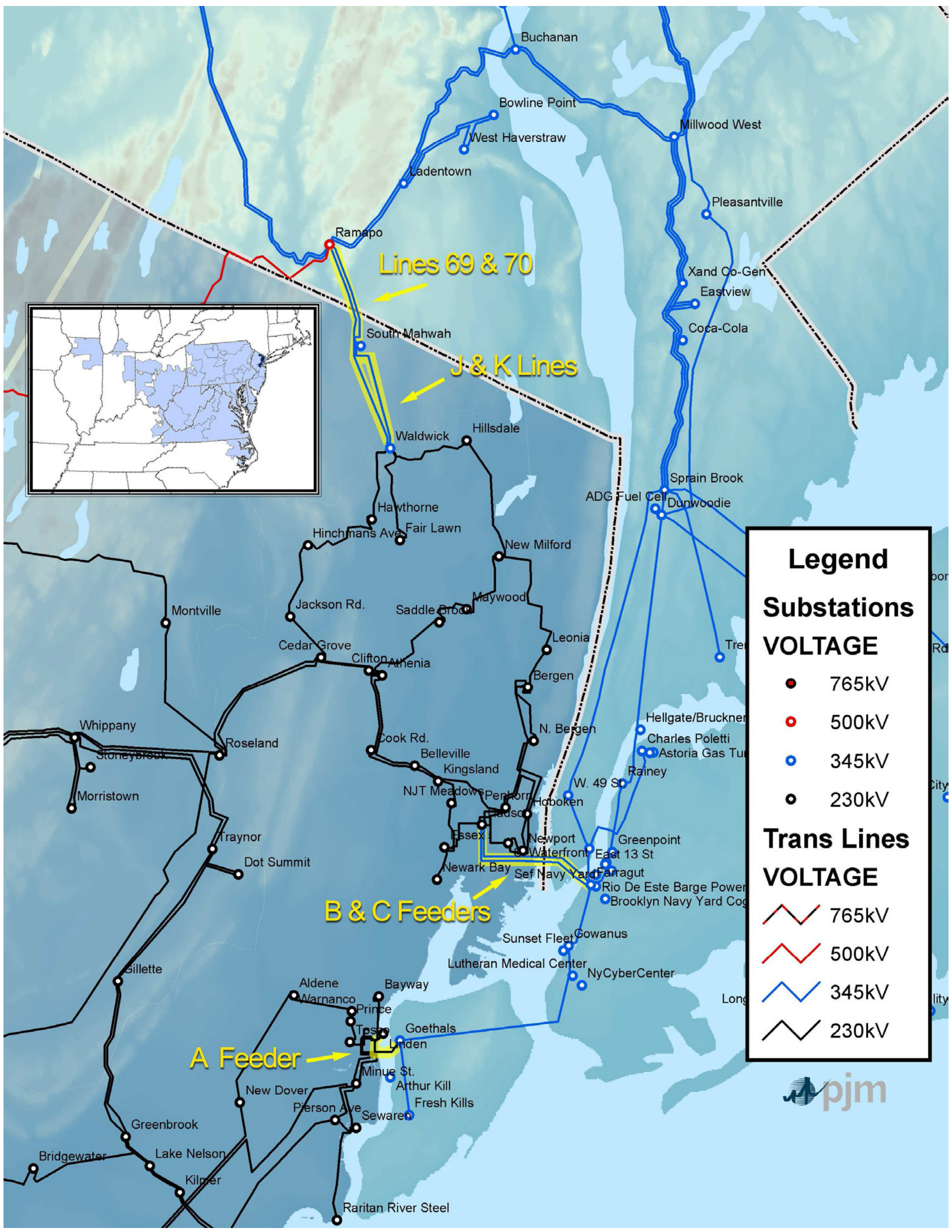
9 111 FERC ¶ 61,228 (2005).

10 "Protest of the Consolidated Edison Company of New York, Inc.," Protest, Docket No. EL02-23-000 (January 30, 2006).

11 120 FERC ¶ 61,161

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City (Figure E-1). Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

Figure E-1 Con Edison and PSE&G wheel



Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties to address the issues raised by Con Edison.[12] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2012, PSE&G's revenues were greater than its congestion charges by $80,727 after adjustments (PSE&G's revenues were greater than its congestion charges by $778,879 in 2011.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2012, Con Edison's congestion credits were $3,627,462 less than its day-ahead congestion charges (Credits had been $2,319,278 less than charges in 2011). Table E-2 shows the monthly details for both PSE&G and Con Edison.

The protocol states:

> If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch. ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[13]

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$42,203 in 2012. The parties should address this issue.

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in 7.7 percent of the hours in 2012.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009, a settlement on behalf of the parties to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.14 By order issued September 16, 2010, the Commission approved this settlement,15 which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU, that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.16 The settlement defined ConEd's cost responsibility for

12 111 FERC ¶ 61,228 (2005).

13 *PJM Interconnection, L.L.C.*, Operating Protocol for the Implementation of Commission Opinion No. 476, Docket No. EL02-23-000 (Phase II) (Effective: July 1, 2005), Original Sheet No. 6 <http://www.pjm.com/~/media/documents/agreements/20050701-attachment-iv-operating-protocol.ashx> (327 KB).

14 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.

15 132 FERC ¶ 61,221.

16 *See, e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).

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.17 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 E-2 below reflecting those charges effective May 1, 2012.

Table E-2 Con Edison and PSE&G wheel settlements data: 2012

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	$31,655	($38)	$31,616	$96,054	$0	$96,054
	Congestion Credit			$5,700			$73,645
	Adjustments			$87			($754)
	Net Charge			$25,829			$23,163
February	Congestion Charge	$40,795	($570)	$40,225	$124,704	$0	$124,704
	Congestion Credit			$7,888			$90,497
	Adjustments			$0			($1,037)
	Net Charge			$32,337			$35,244
March	Congestion Charge	$212,620	$310	$212,930	$323,108	$0	$323,108
	Congestion Credit			$74,365			$293,945
	Adjustments			$0			($1,121)
	Net Charge			$138,564			$30,284
April	Congestion Charge	$157,737	$54,006	$211,743	$321,351	$0	$321,351
	Congestion Credit			$18,543			$205,689
	Adjustments			($7,769)			($3,046)
	Net Charge			$200,969			$118,708
May	Congestion Charge	$1,425,238	($615)	$1,424,623	$0	$0	$0
	Congestion Credit			$0			$289,527
	Adjustments and Transmission Charges			($2,775,525)			($37)
	Net Charge			$4,200,148			($289,490)
June	Congestion Charge	$353,769	$67,757	$421,526	$0	$0	$0
	Congestion Credit			$312,781			$0
	Adjustments and Transmission Charges			($2,773,835)			$0
	Net Charge			$2,882,580			$0
July	Congestion Charge	$93,567	$0	$93,567	$0	$0	$0
	Congestion Credit			$63,666			$0
	Adjustments and Transmission Charges			($2,994,092)			($1,382)
	Net Charge			$3,023,992			$1,382

17 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.

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
August	Congestion Charge	$12,757	$0	$12,757	$0	$0	$0
	Congestion Credit			$8,838			$0
	Adjustments and Transmission Charges			($2,943,519)			$0
	Net Charge			$2,947,438			$0
September	Congestion Charge	$1,868,692	$114,181	$1,982,873	$0	$0	$0
	Congestion Credit			$782,643			$0
	Adjustments and Transmission Charges			($2,798,578)			$8
	Net Charge			$3,998,807			($8)
October	Congestion Charge	$678,251	($132,724)	$545,527	$0	$0	$0
	Congestion Credit			$226,409			$0
	Adjustments and Transmission Charges			($2,890,254)			$3
	Net Charge			$3,209,372			($3)
November	Congestion Charge	$169,407	$11,637	$181,044	$0	$0	$0
	Congestion Credit			$133,786			$0
	Adjustments and Transmission Charges			($2,849,659)			$3
	Net Charge			$2,896,917			($3)
December	Congestion Charge	$678,112	($9,239)	$668,874	$0	$0	$0
	Congestion Credit			$460,517			$0
	Adjustments and Transmission Charges			($3,116,156)			$4
	Net Charge			$3,324,512			($4)
Total	Congestion Charge	$5,722,599	$104,705	$5,827,303	$865,217	$0	$865,217
	Congestion Credit			$2,095,137			$953,303
	Adjustments and Transmission Charges			($23,149,300)			($7,358)
	Net Charge			$26,881,466			($80,727)

Ancillary Service Markets

This appendix covers three areas related to Ancillary Service Markets: area control error, the details of regulation availability and price determination, and the clearing process for the Synchronized Reserve Market.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[2]

On October 1, 2012, PJM implemented Performance Regulation in response to FERC Order 755 to promote new sources and types of regulation which offer lower MW capabilities but faster and more accurate response to the PJM regulation signal. PJM now measures the performance of each regulating resource at 10 second intervals combining the results into an hourly performance score. The performance score is then used in the calculation of settlement credits. Hourly performance scores are also saved to create a 100-hour rolling performance score which is used calculate an effective performance offer and capability offer from a resource's actual performance offer and capability offer during market clearance and in satisfying the regulation requirement. The performance score is calculated as a function of three distinct measurements performed against the unit's response to the regulation signal. The measurements are correlation, delay, and precision.[3]

Resources wishing to participate in the Regulation Market must pass three consecutive certification tests. Certification requires that resources be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to their regulation signal (RegA or RegD) with a score of 75 percent or better. If a resource has its historic performance score fall below 40 percent for a signal type, that resource becomes ineligible to offer regulation in that signal type and must re-certify in that signal type before offering regulation in that signal type again.[4]

Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL)

- Control Performance Standard 1 (CPS1) and Balancing Authority Ace Limit (BAAL) are standard metrics used to measure and report the effectiveness of ACE control. The purpose of the CPS1/BAAL standards is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

- **CPS1.** CPS1 is a statistical measure of ACE variability and its relationship to frequency error. It is measured each minute. It is intended to provide a frequency-sensitive evaluation of how well PJM meets its demand requirements with its supply resources. The maximum CPS1 score is 200 percent. This is achieved when either the frequency error is zero or the ACE is zero. The minimum passing score is 100 percent monthly.

1 The PJM Manuals define ACE: "Area Control Error is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts. Two additional terms may be included in ACE under certain conditions--the time error bias term and PJM dispatcher adjustment term (manual add). These provide for automatic inadvertent interchange payback and error compensation, respectively." PJM. "Manual 12: Balancing Operations," Revision 27 (December 20, 2012), para. 3.1.1, "PJM Area Control Error" p. 12.

2 Regulation Market business rules are defined in PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 57 (December 1, 2012), pp. 52-66.

3 A full specification for each of these measurements is in PJM M-12 "Balancing Operations," Rev 27 (December 20, 2012), para. 4.5.6 pp 52-54.

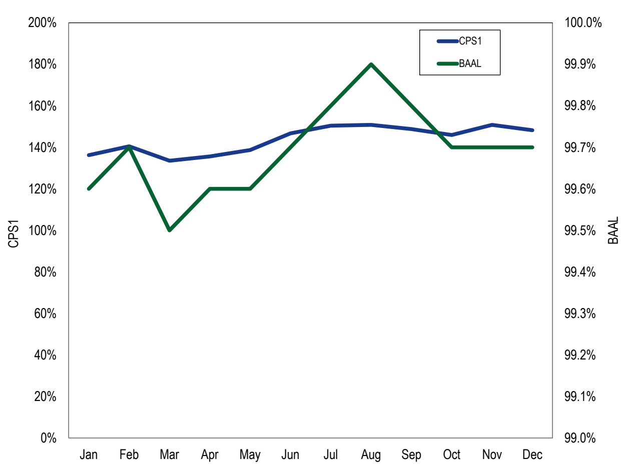
4 See "Manual 12: Balancing Operations," Revision 27 (December 20, 2012), Section 4.5.5, pg. 51.

- **BAAL.** Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which establishes a new metric, balancing authority ACE limit (BAAL). PJM counts the total number of minutes that ACE complies with the BAAL limits (high and low) and divides it by the total number of minutes for a month, with a passing level for this goal being set at 99.0 percent for each month.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance for both CPS1 and BAAL metrics was acceptable throughout 2012. The regulation requirement was reduced in the last quarter of 2012 after the introduction of the new performance based Regulation Market. The requirement was reduced from one percent of the peak load forecast during on-peak hours and one percent of the valley load during off-peak hours to 0.7 percent of the peak load forecast during on-peak hours and 0.7 percent of the valley load during off-peak hours.

Figure F-1 PJM CPS1/BAAL performance: 2012



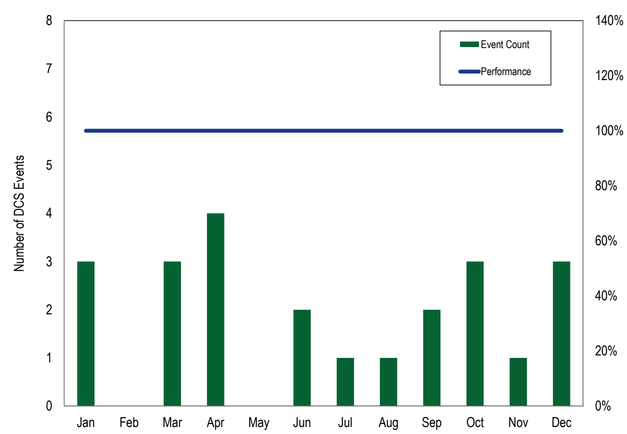
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 and BAAL standards requires PJM dispatchers to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

PJM's DCS Performance

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[5] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation greater than, or equal to, 80 percent of the magnitude of PJM's most severe single contingency loss. PJM currently interprets this to be any ACE deviation greater than 1,000 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 23 DCS events during 2012 and successfully recovered from all of them. Recovery times ranged from five minutes to 19 minutes. Figure F-2 illustrates the event count by month. All of the events resulted in low ACE. The solution in all 23 events was to declare a spinning event.

Figure F-2 DCS event count and PJM performance (By month): 2012



Regulation Market Changes for Performance Based Regulation

Regulation is a key part of PJM's effort to minimize ACE so as 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 markets so as to make use of and properly compensate a mix of fast and traditional

5 For more information on the NERC DCS, see "Standard BAL-002-0 – Disturbance Control Performance" (April 1, 2005) < www.nerc.com/files/BAL-002-0.pdf> (61 KB).

response regulation resources.[6] Prior to October 1, 2012, regulation consisted of energy that could be added or removed within five minutes following a traditional (RegA) signal. Performance Based Regulation includes a new class of regulation resources capable of responding to a new, faster signal called RegD. Under the new performance based Regulation Market design, providers offer both regulation capability (MW) and regulation mileage per MW of capability (ΔMW/MW). The performance based Regulation Market is PJM's response to FERC Order No. 755.

Due to their varying characteristics, fast (Reg D following) and slow (Reg A following) resources are not perfect substitutes for one another for purposes of providing regulation as defined in PJM's market. But because regulation is a single product in PJM's market design, the clearing rules must account for and optimize the selection of fast and slow resources included in the market clearing.

Fast and slow resources, depending on technology type, have different cost structures, different sources, and different capabilities. Fast resources, for example, tend to be non-generation resources. Fast resources have quick response times but limited total response capability in one direction relative to slow resources. PJM has historically met its regulation requirements via the use of slow resources following a single regulation signal (RegA) designed to reflect the characteristics of slow resources in meeting ACE and frequency control requirements. Although fast resources can respond quickly to changes in RegA, they cannot always successfully track the RegA signal. When RegA is negative or positive for a significant period of time, non-generator, fast response units, such as fly wheels and batteries, quickly exhaust their capability to follow the signal. When RegA has many small displacements and crosses zero often, non-generator fast response units can more closely track RegA than traditional slow resources.

Generally speaking, fast response units are better suited to follow a signal that makes frequent changes from negative to positive and slow resources are better suited to follow a signal that makes less frequent changes from negative to positive. Regulation service defined around only one signal cannot take full advantage of the capability that either fast or slow resources can provide. A signal designed to take advantage of a particular resource type (fast or slow), will tend to diminish the ability of the other resource type to contribute to ACE and frequency control.

Due to the nature of the Regulation Market in PJM it is possible to meet PJM's regulation requirements (the regulation performance target) entirely with slow resources following RegA. PJM cannot, however, meet its regulation requirements (regulation performance target) using only fast resources, even with a fast resource specific regulation signal (RegD).

Although PJM cannot replace its slow regulation fleet with a fast regulation fleet, the KEMA Study indicated that a combination of fast and slow resources, following separate fast (RegD) and slow (RegA) regulation signals, could do a more effective job of meeting PJM's regulation requirement (regulation performance target) than slow resources alone. According to the study, the smaller the proportion of fast regulation MW and the greater the proportion of slow regulation used, the more benefit there is to substituting fast regulation MW for slow regulation MW. In other words, the smaller the proportion of fast regulation used, the more slow regulation each MW of fast regulation can replace. Conversely, as the proportion of fast resources increases, the benefit of substituting fast capability for slow capability in meeting a specific regulation performance target decreases. In other words, the larger the proportion of fast regulation used, the less slow regulation each MW of fast regulation can replace. This is not surprising and follows a normal diminishing returns pattern. This relationship is the benefits factor, or rate of substitution, between fast and slow resources. The benefits factor decreases as the amount of fast resources increases.

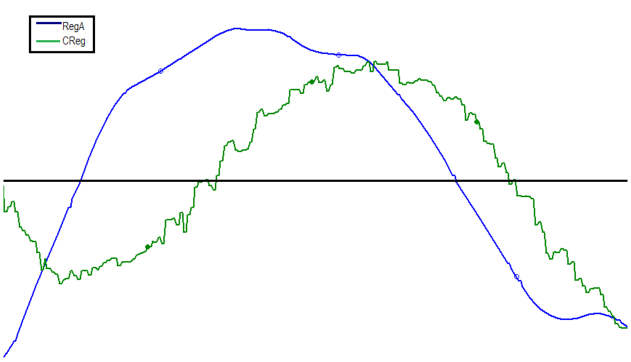
The KEMA Study indicated that, for a given regulation performance target, there is a limit to this ability to substitute fast for slow regulation MW and reduce total combined regulation MW when trying to achieve a specific regulation performance target. This is why PJM cannot entirely replace its slow regulation fleet following a RegA signal with a fast regulation fleet following a RegD signal. Although the rate of substitution is greater than 1.0 when the level of fast

6 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011) ("Order No. 755").

regulation is low (one MW of fast can replace more than one MW of slow while holding regulation performance target constant), the rate of substitution falls as more fast regulation MW are added. The rate of substitution is the marginal benefits factor. Eventually, the addition of another MW of fast capability actually requires adding rather than replacing MW of slow capability to maintain a regulation performance target. At this point the rate of substitution is negative (less than zero) and the addition of fast resources makes it harder to maintain a regulation performance target. PJM's current implementation prevents the rate of substitution (the benefits factor) from falling below zero. While this is incorrect, it is unlikely to have any practical effect as the price of fast resources is likely to be very high under those conditions.

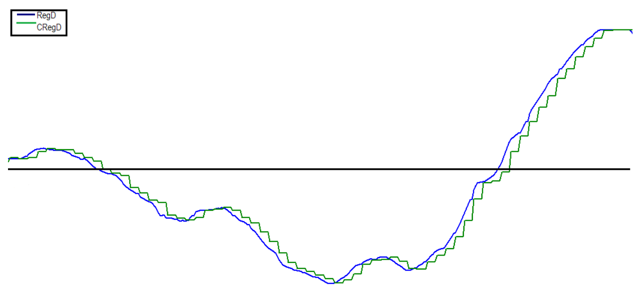
Reg A is a signal developed by PJM to moderate ACE. It is designed for the class of regulating resources able to begin responding to change in output and respond fully within five minutes to their full regulating capability. This signal is generally developed for steam, and CC units, with between a few percent up to 25 percent of hydro regulation. Figure F-3 shows a screenshot of typical 10-minute time period of PJM's RegA signal and CReg compliance signal.

Figure F-3 PJM RegA signal and CReg compliance signal. Screenshot of typical 10-minute time period



RegD is a regulation signal developed by PJM designed to moderate ACE. It is designed for the class of regulating units that can respond within a few seconds and reach their full response capability within one to two minutes. It is designed for units that respond quickly and accurately but may not have high capability or capacity at full max or min for a full hour. Figure F-4 shows a screenshot of typical 10-minute time period of PJM's RegD signal and CReg compliance signal.

Figure F-4 PJM RegD signal and CRegD compliance signal. Screenshot of typical 10-minute time period



Regulation signals are designed for the purpose of moderating ACE. The design must account for the characteristics of the expected response. The design of the RegD signal to favor the attributes of fast regulation resources is part of the FERC Order 755 mandate. But ultimately the reason for regulation is to counteract ACE and both signals must be designed to accomplish that end. Even a very fast regulating unit will need to have some capacity and MW to help with ACE correction, and even a unit with a large MW capability must be able to react with some sensitivity and speed to help with ACE correction. The relationship between the two types of regulating resources is under constant review and the relationship between the two (expressed in the Benefits Factor) is subject to change.

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capability price in $/MW at cost plus up to $12 adder daily into the Regulation Market using the PJM market user interface. Users must also enter the signal type they want to follow (RegA or RegD), their regulation capability in MW, as well as cost validation parameters - fuel cost, heat rate at economic maximum, heat rate at regulation minimum, and the VOM rate. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Owners may also enter price based offers up to a maximum of $100/MW. Demand resources are eligible to offer regulation and did so for the first time in November of 2011. Demand resources have an LOC of zero.

Under current PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. All regulation offers that are not set to "unavailable" for the day are summed to calculate the total daily regulation offered, a figure that changes each hour.

- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs the Ancillary Services Optimizer software (ASO) to determine the amount of Tier 2 synchronized reserve/non-synchronized reserve required, develop regulation and synchronized reserve supply curves, and assign regulation, synchronized reserve, and non-synchronized reserve to specific units. All regulation resource units which have made offers in the daily Regulation Market are evaluated by ASO for regulation. ASO excludes units according to the following ordered criteria: a) Daily or hourly unavailable status; b) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); c) Units which are assigned synchronized reserve; d) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); e) Units that are offline (except combustion turbine units).

Even after ASO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically for several reasons including: to control transmission constraints; to avoid overgeneration during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.

For each offered and eligible unit in the regulation supply, the regulation total capability offer price is calculated using the sum of the unit's regulation cost-based offer (divided by the benefits factor of the resource type and the historic performance score of the resource) plus the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule.[7] Based on this result, ASO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. ASO uses price-based offers for those operators not offer capped and re-solves. Unit assignments based on this solution are final. The final clearing price is not determined at the time of unit assignment.

The Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets are cleared, prior to the hour, and supplementally within the hour, on a real time basis. The Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets are cleared and priced interactively with the Energy Market and secondary reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, inter area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements, reserve requirements and prior to the hour assignments for regulation and reserves. The final clearing prices are calculated at five-minute intervals based on the real time prices and LMPs of energy. These five-minute prices are averaged to arrive at the final hourly clearing price. This price is sent to Settlements and used and the basis for credits and charges.

- **Cleared Regulation.** Regulation actually assigned by ASO is cleared regulation. The capability and performance prices are calculated every five minutes by the Locational Pricing Calculator (LPC) with the final hourly clearing price averaged from the five minute prices. In real time, units that have been assigned regulation, synchronized reserve, and non-synchronized reserve are expected to

7 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" for a full discussion of opportunity costs.

provide regulation, synchronized reserve, and non-synchronized reserve for the designated hour.

- **Settled Regulation.** Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW, or effective MW) plus any actual lost opportunity costs associated with providing regulation. The cost per MW of settled regulation can be higher than the regulation clearing price because there can be a difference between actual and cleared MW, as well as real-time versus forecast nodal prices.

Synchronized Reserve Market Clearing

PJM's market clearing engines consider resources capable of providing Tier 2 synchronized reserve as being either flexible or inflexible. Flexible resources are those resources that are online, dispatchable, and have offers for Tier 2 synchronized reserve. Inflexible resources are either synchronous condensers or DSR. In the Mid-Atlantic Dominion Subzone, the following four steps occur to clear and price the market for Tier 2 synchronized reserve.

First, one hour before the market hour, ASO estimates the sum of the available Tier 1 synchronized reserve within the MAD Subzone and the available transfer capacity from outside the MAD Subzone. Next, ASO subtracts this estimate from the MAD Subzone synchronized reserve requirement to determine the amount of Tier 2 synchronized reserve needed to satisfy the requirement. Then, ASO generates a co-optimized solution for this amount of Tier 2 synchronized reserve. Finally, ASO logs the amount of Tier 2 synchronized reserve comprised of inflexible resources, commits these resources to provide Tier 2 synchronized reserve, and notifies these resources through eMKT. The amount of Tier 2 synchronized reserve provided by flexible resources is not logged and is not carried through to later steps in the clearing process.

Second, half an hour before the market hour, IT SCED performs the same functions as ASO up to the point of logging and committing individual resources, taking into account the amount of inflexible resources already committed by ASO. IT SCED, however, does not consider DSR in its solution. After IT SCED produces its solution, a PJM operator reviews the solution, calls the inflexible resources to commit them to provide Tier 2 synchronized reserve, and logs each resource separately. As with ASO, the amount of Tier 2 synchronized reserve provided by flexible resources is not logged and is not carried through to later steps in the clearing process.

Third, 15 minutes before each five-minute period in the market hour, RT SCED estimates the amount of needed Tier 2 synchronized reserve, taking into account the amount of inflexible resources already committed by ASO and IT SCED. RT SCED considers only flexible resources due to the notification-time requirements of inflexible resources. Once RT SCED generates its solution, RT SCED commits the resources from its solution and logs these resources.

Lastly, every five minutes within the market hour, LPC calculates market clearing prices by incorporating resource offers and LOC based on real-time LMP and marginal cost. LPC computes the price of one additional MW of Tier 2 synchronized based on these factors and the committed resources and uses this price as the within-hour five-minute clearing price. For the hour, the Synchronized Reserve Market Clearing Price is the simple average of the 12 five-minute clearing prices.

Whereas the hourly price is the average of the within-the-hour five-minute prices, the hourly cost (per MW) is the sum of credits for cleared and self-scheduled (and, prior to October 1, added out-of-market) synchronized reserve and credits for after-market lost opportunity cost divided by the total MW of synchronized reserve cleared and self-scheduled (and, prior to October 1, added out-of-market). Price is regularly less than cost, occasionally very close to cost, but never more than cost. PJM guarantees resources to be made whole to their offer plus opportunity costs.

Congestion and Marginal Losses

Locational Marginal Price (LMP) is the incremental price of energy at a bus. LMP at any bus is made up of three components: the system marginal price (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product 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 transmission constraints. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the generation of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[1] Congestion results from physical limitations of elements of the transmission system to move power from point to point. Congestion costs reflect the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, 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.

LMP Components Real-Time and Day-Ahead

Table G-1 shows the components of real-time LMP from 2008 through 2012. Table G-2 compares 2011 real-time LMP components by zone to 2012 real-time LMP components by zone. Table G-3 compares 2011 real-time LMP components by hub to 2012 LMP components by hub. Table G-4 shows the components of day-ahead LMP from 2008 through 2012. Table G-5 compares 2011 day-ahead LMP components by zone to 2012 day-ahead LMP components by zone.

Table G-1 PJM real-time, average LMP components (Dollars per MWh): 2008 through 2012

Year	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$44.83	$44.72	$0.07	$0.04
2011	$42.84	$42.77	$0.05	$0.02
2012	$33.11	$33.06	$0.04	$0.01

1 For additional information, see the *MMU Technical Reference for PJM Markets*, at, "Marginal Losses."

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.

Table G-2 Zonal real-time, average LMP components (Dollars per MWh): 2011 and 2012

	2011				2012			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$47.56	$42.77	$2.80	$1.99	$34.20	$33.06	($0.09)	$1.22
AEP	$39.04	$42.77	($2.41)	($1.32)	$31.70	$33.06	($0.59)	($0.77)
AP	$42.91	$42.77	$0.23	($0.09)	$33.08	$33.06	$0.09	($0.07)
ATSI	$39.24	$41.20	($1.79)	($0.17)	$32.61	$33.06	($0.64)	$0.18
BGE	$49.11	$42.77	$4.40	$1.93	$37.22	$33.06	$2.69	$1.47
ComEd	$33.30	$42.77	($6.92)	($2.55)	$29.25	$33.06	($2.23)	($1.58)
DAY	$39.22	$42.77	($2.81)	($0.74)	$32.35	$33.06	($0.74)	$0.02
DEOK	NA	NA	NA	NA	$30.91	$33.06	($0.65)	($1.51)
DLCO	$38.98	$42.77	($2.48)	($1.31)	$31.72	$33.06	($0.36)	($0.98)
Dominion	$46.38	$42.77	$3.02	$0.60	$34.69	$33.06	$1.26	$0.37
DPL	$47.33	$42.77	$2.32	$2.25	$36.15	$33.06	$1.64	$1.45
JCPL	$47.65	$42.77	$2.84	$2.04	$34.06	$33.06	($0.15)	$1.15
Met-Ed	$45.82	$42.77	$2.34	$0.72	$33.96	$33.06	$0.44	$0.46
PECO	$46.56	$42.77	$2.37	$1.42	$34.08	$33.06	$0.24	$0.77
PENELEC	$42.95	$42.77	($0.19)	$0.37	$33.50	$33.06	($0.10)	$0.54
Pepco	$47.34	$42.77	$3.44	$1.13	$36.33	$33.06	$2.38	$0.88
PPL	$45.84	$42.77	$2.42	$0.65	$33.40	$33.06	($0.13)	$0.46
PSEG	$48.17	$42.77	$3.30	$2.10	$34.79	$33.06	$0.48	$1.24
RECO	$44.28	$42.77	($0.37)	$1.88	$34.36	$33.06	$0.17	$1.13
PJM	$42.84	$42.77	$0.05	$0.02	$33.11	$33.06	$0.04	$0.01

Table G-3 Hub real-time, average LMP components (Dollars per MWh): 2011 and 2012

	2011				2012			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$37.08	$42.77	($3.00)	($2.69)	$30.46	$33.06	($0.84)	($1.77)
AEP-DAY Hub	$38.55	$42.77	($2.69)	($1.52)	$31.55	$33.06	($0.67)	($0.84)
ATSI Gen Hub	$38.87	$41.19	($1.77)	($0.55)	$32.19	$33.06	($0.64)	($0.23)
Chicago Gen Hub	$32.25	$42.77	($7.41)	($3.10)	$28.28	$33.06	($2.73)	($2.05)
Chicago Hub	$33.48	$42.77	($6.78)	($2.51)	$29.43	$33.06	($2.11)	($1.52)
Dominion Hub	$45.84	$42.77	$2.87	$0.20	$34.19	$33.06	$1.04	$0.08
Eastern Hub	$47.71	$42.77	$2.48	$2.47	$36.55	$33.06	$1.91	$1.58
N Illinois Hub	$33.07	$42.77	($6.95)	($2.76)	$28.95	$33.06	($2.38)	($1.73)
New Jersey Hub	$47.88	$42.77	$3.08	$2.03	$34.45	$33.06	$0.19	$1.19
Ohio Hub	$38.58	$42.77	($2.73)	($1.45)	$31.66	$33.06	($0.64)	($0.76)
West Interface Hub	$40.57	$42.77	($1.21)	($0.99)	$32.50	$33.06	($0.04)	($0.52)
Western Hub	$43.56	$42.77	$0.88	($0.09)	$33.90	$33.06	$0.77	$0.07

Table G-4 PJM day-ahead, average LMP components (Dollars per MWh): 2008 through 2012

Year	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	$0.06	$0.09
2010	$44.57	$44.61	$0.03	($0.06)
2011	$42.52	$42.72	($0.07)	($0.13)
2012	$32.79	$32.72	$0.09	($0.01)

Table G-5 Zonal day-ahead, average LMP components (Dollars per MWh): 2011 and 2012

	2011				2012			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$47.86	$42.72	$2.84	$2.30	$34.36	$32.72	$0.28	$1.36
AEP	$39.32	$42.72	($1.93)	($1.47)	$31.45	$32.72	($0.37)	($0.90)
AP	$42.96	$42.72	$0.29	($0.05)	$32.82	$32.72	$0.14	($0.04)
ATSI	$39.34	$41.59	($1.37)	($0.88)	$32.11	$32.72	($0.55)	($0.07)
BGE	$48.66	$42.72	$3.69	$2.25	$36.91	$32.72	$2.42	$1.77
ComEd	$33.46	$42.72	($6.15)	($3.12)	$28.80	$32.72	($2.08)	($1.85)
DAY	$39.29	$42.72	($2.60)	($0.83)	$32.10	$32.72	($0.47)	($0.15)
DEOK	NA	NA	NA	NA	$30.73	$32.72	($0.33)	($1.66)
DLCO	$38.89	$42.72	($2.52)	($1.31)	$31.53	$32.72	($0.19)	($1.00)
Dominion	$46.00	$42.72	$2.61	$0.66	$34.39	$32.72	$1.18	$0.48
DPL	$47.93	$42.72	$2.61	$2.59	$35.86	$32.72	$1.30	$1.83
JCPL	$47.59	$42.72	$2.48	$2.38	$34.24	$32.72	$0.23	$1.29
Met-Ed	$45.82	$42.72	$2.37	$0.72	$33.68	$32.72	$0.37	$0.59
PECO	$47.21	$42.72	$2.71	$1.78	$34.02	$32.72	$0.37	$0.92
PENELEC	$42.79	$42.72	($0.17)	$0.24	$33.41	$32.72	$0.10	$0.59
Pepco	$47.58	$42.72	$3.35	$1.51	$36.05	$32.72	$2.12	$1.21
PPL	$45.68	$42.72	$2.37	$0.59	$33.19	$32.72	$0.03	$0.43
PSEG	$48.32	$42.72	$3.06	$2.53	$34.76	$32.72	$0.54	$1.49
RECO	$45.80	$42.72	$1.13	$1.95	$34.08	$32.72	$0.14	$1.22
PJM	$42.52	$42.72	($0.07)	($0.13)	$32.79	$32.72	$0.09	($0.01)

Congestion Costs

Zonal Congestion Costs

Day-ahead and balancing congestion costs within zones for 2011 and 2010 are presented in Table G-6 and Table G-7.[3] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear congestion costs. Load congestion payments, when positive, measure the congestion cost to load in an area. Load congestion payments, when negative, measure the congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the congestion credit to generation in an area. Generation congestion credits, when negative, measure the congestion cost to generation in an area. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

PJM congestion accounting nets load congestion payments against generation congestion credits by billing organization. The net congestion bill for a zone or constraint may be either positive or negative, depending on the relative size and sign of load congestion payments and generation congestion credits. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for an area, not including explicit congestion. But the net congestion bill is not a good measure of whether load is paying higher prices in the form of congestion.

The ComEd Control Zone, AEP Control Zone and the AP Control Zone are examples of how a positive net congestion bill can result from very different

3 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change. As of March 2, 2013, the total zonal congestion related numbers presented here differed from the March 2, 2013 PJM totals by $0.10 Million, a discrepancy of 0.02 percent (.00019).

combinations of load payments and generation credits. The ComEd Control Zone had the highest congestion charges, $171.0 million, of any control zone in 2012. The positive congestion costs in the ComEd Control Zone were the result of large negative load congestion payments offset by even larger negative generation congestion credits. Thus, the lower prices in ComEd, which resulted from a lower congestion component of LMP, meant that load paid lower prices and lower congestion, and that generators received lower prices and a lower congestion component. The result was positive measured congestion costs. This somewhat counter intuitive result is the result of congestion accounting conventions.

The AEP Control Zone had the second highest congestion charges, $104.2 million, of any control zone in 2012. The positive congestion costs in the AEP Control Zone were the result of negative load congestion payments offset by a bigger negative generation congestion credits. The Dominion Control Zone had the third highest congestion charges, $63.3 million, of any control zone in 2012. The positive congestion costs in the Dominion Control Zone were the result of relatively low positive load congestion payments and larger negative generation congestion credits, which added to the total congestion costs for Dominion rather than offsetting the positive load congestion payments.

Table G-6 Congestion cost summary (By control zone): 2012

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$7.5	$3.5	$0.5	$4.4	$0.0	$0.5	($0.3)	($0.7)	$3.7
AEP	($81.4)	($189.5)	$23.3	$131.4	$5.9	$14.5	($18.6)	($27.2)	$104.2
AP	$5.1	($52.6)	$8.7	$66.4	$3.7	$9.1	($8.4)	($13.8)	$52.5
ATSI	($50.7)	($55.7)	$1.4	$6.5	$2.7	$6.0	$0.4	($3.0)	$3.5
BGE	$140.1	$103.7	$11.3	$47.7	$1.4	$1.4	($13.4)	($13.3)	$34.4
ComEd	($337.6)	($539.3)	$16.4	$218.2	$3.4	$17.7	($32.9)	($47.2)	$171.0
DAY	($12.6)	($15.2)	$7.4	$9.9	$0.6	$1.7	($3.9)	($4.9)	$5.0
DEOK	($12.3)	($14.4)	$5.9	$8.0	$0.6	$0.6	($4.9)	($5.0)	$3.0
DLCO	($5.1)	($14.8)	$0.6	$10.3	$0.1	$0.3	($0.3)	($0.6)	$9.7
DPL	$47.5	$16.2	$4.6	$35.9	($10.8)	$2.6	($7.7)	($21.1)	$14.8
Dominion	$228.2	$164.7	$15.8	$79.2	$3.2	($0.9)	($20.0)	($16.0)	$63.3
External	($42.9)	($26.8)	($0.2)	($16.4)	($9.0)	($3.0)	($33.7)	($39.7)	($56.0)
JCPL	$11.3	$1.5	$1.0	$10.7	$1.9	$1.7	$0.1	$0.3	$11.1
Met-Ed	$9.4	($0.6)	$1.5	$11.4	$0.0	$1.9	($2.6)	($4.5)	$7.0
PECO	$36.2	$20.4	$1.4	$17.2	$1.5	$5.0	($1.3)	($4.7)	$12.5
PENELEC	($2.5)	($35.0)	$2.4	$34.8	$0.9	$0.8	($2.0)	($1.9)	$32.9
PPL	$5.3	($5.6)	$1.1	$12.0	$2.0	$2.7	($0.6)	($1.3)	$10.7
PSEG	$45.6	$30.5	$17.6	$32.7	$1.4	$7.1	($22.6)	($28.3)	$4.4
Pepco	$143.9	$96.3	$11.1	$58.8	($6.6)	($1.2)	($12.6)	($18.0)	$40.8
RECO	$0.5	$0.0	$0.1	$0.6	$0.1	$0.0	($0.2)	($0.1)	$0.5
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$529.0

Table G-7 Congestion cost summary (By control zone): 2011

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$45.4	$15.7	$0.7	$30.5	($0.4)	$0.2	($1.0)	($1.6)	$28.9
AEP	($377.8)	($606.7)	$23.0	$251.8	$9.4	$37.2	($28.9)	($56.7)	$195.1
AP	$6.9	($143.7)	($2.6)	$148.1	$5.7	$8.0	($1.8)	($4.1)	$143.9
ATSI	($73.8)	($78.5)	$1.6	$6.3	$2.1	$8.0	($3.3)	($9.2)	($2.9)
BGE	$233.4	$180.3	$8.0	$61.0	$2.8	$1.8	($11.5)	($10.5)	$50.5
ComEd	($1,064.7)	($1,323.5)	($4.2)	$254.6	$57.4	$46.2	($26.7)	($15.5)	$239.0
DAY	($61.3)	($70.1)	$1.3	$10.1	$3.4	$6.1	($4.4)	($7.1)	$3.0
DLCO	($43.2)	($67.9)	$0.0	$24.7	($3.0)	$0.7	($0.7)	($4.4)	$20.4
DPL	$71.3	$28.6	$1.3	$44.0	$0.5	$3.9	($1.8)	($5.2)	$38.8
Dominion	$537.7	$375.1	$23.1	$185.7	($4.8)	$4.5	($37.7)	($47.0)	$138.7
External	($56.3)	($42.5)	($6.5)	($20.3)	($10.4)	($19.1)	($23.8)	($15.1)	($35.4)
JCPL	$78.8	$35.4	$1.0	$44.4	$3.9	$1.3	($1.5)	$1.1	$45.5
Met-Ed	$46.0	$48.1	$0.5	($1.7)	$1.7	$0.8	($0.7)	$0.2	($1.5)
PECO	$178.0	$163.2	$0.9	$15.7	($0.9)	$5.2	($1.1)	($7.2)	$8.5
PENELEC	($45.9)	($108.1)	$0.7	$62.9	$4.2	$7.2	($1.2)	($4.2)	$58.7
PPL	$137.2	$142.1	$5.0	$0.0	$6.7	$2.9	($3.3)	$0.5	$0.5
PSEG	$191.8	$154.3	$7.6	$45.1	$1.3	$17.7	($33.9)	($50.4)	($5.3)
Pepco	$230.7	$156.5	$5.4	$79.6	($3.6)	($1.8)	($6.6)	($8.4)	$71.1
RECO	$2.3	($0.1)	$0.1	$2.6	$0.0	$1.0	($0.2)	($1.1)	$1.5
Total	$36.3	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0

Details of Regional and Zonal Congestion

Constraints can affect prices and congestion across multiple zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM Western Region with seven control zones (the AP, ATSI, ComEd, AEP, DLCO, DEOK and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table G-8 through Table G-44 present the top 15 constraints affecting each control zone's congestion costs, including the facility type and the location of the constrained facility for both 2012 and 2011. In addition, day-ahead and real-time congestion-event hours are presented for each of the highlighted constraints. The tables present the constraints in descending order of the absolute value of total congestion costs for each zone. In addition to the top 15 constraints, these tables show the top five local constraints for the control zone, which were not in the top 15 constraints, but are located inside the respective control zone. In 2012, the RECO control zone only had one internal constraint, thus the RECO table shows the top 15 constraints and one local constraint.

For each of the constraints presented in the following tables, the zonal cost impacts are decomposed into their Day-Ahead Energy Market and balancing market components. 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.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table G-8 AECO Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	($5.5)	($1.5)	($0.1)	($4.1)	$0.0	$0.1	$0.1	$0.0	($4.1)	5,328	1,446
2	West	Interface	500	$4.1	$1.8	$0.1	$2.3	($0.1)	$0.1	($0.0)	($0.2)	$2.1	1,682	260
3	Northwest	Other	BGE	($1.3)	($0.3)	($0.0)	($0.9)	($0.0)	$0.1	$0.0	($0.1)	($1.0)	1,168	804
4	Buxmont - Whitpain	Line	PECO	$1.4	$0.6	$0.1	$0.9	($0.0)	($0.0)	($0.0)	$0.0	$0.9	638	6
5	East	Interface	500	$1.1	$0.4	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.1	$0.7	418	10
6	AP South	Interface	500	$0.9	$0.3	$0.1	$0.7	$0.0	($0.0)	($0.1)	($0.0)	$0.7	5,172	702
7	5004/5005 Interface	Interface	500	$0.5	$0.2	$0.0	$0.3	$0.1	($0.1)	($0.0)	$0.2	$0.5	382	256
8	Bedington - Black Oak	Interface	500	$0.7	$0.2	$0.0	$0.5	($0.0)	$0.0	($0.0)	($0.0)	$0.4	1,560	108
9	Clover	Transformer	Dominion	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	($0.1)	($0.0)	$0.4	3,128	904
10	Rantoul - Rantoul Jct	Flowgate	MISO	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	4,072	630
11	Crete - St Johns Tap	Flowgate	MISO	$0.5	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	4,754	554
12	Higbee - Lewis	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.1)	($0.3)	($0.3)	4	52
13	Loudoun - Gainsville	Line	Dominion	$0.6	$0.3	$0.0	$0.3	$0.0	($0.0)	($0.0)	($0.0)	$0.3	322	38
14	Shieldalloy - Vineland	Line	AECO	$0.5	$0.1	$0.1	$0.5	($0.1)	($0.0)	($0.1)	($0.1)	$0.3	952	114
15	Palisades - Roosevelt	Flowgate	MISO	$0.4	$0.1	($0.0)	$0.3	$0.0	$0.0	$0.0	($0.0)	$0.3	1,710	418
24	Monroe - Shieldalloy	Line	AECO	$0.2	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	494	0
27	Corson - Union	Line	AECO	$0.1	($0.0)	($0.0)	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	50	2
36	Absecon - Lewis	Line	AECO	$0.2	$0.0	$0.0	$0.2	$0.1	$0.2	($0.0)	($0.1)	$0.1	108	34
46	Sherman Avenue	Transformer	AECO	$0.1	$0.0	$0.0	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.1	288	8
50	Corson - Sea Isle	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.1	$0.1	0	16

Table G-9 AECO Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$9.7	$3.7	$0.1	$6.1	$0.0	($0.0)	($0.0)	$0.0	$6.1	1,758	40
2	5004/5005 Interface	Interface	500	$7.4	$3.3	$0.0	$4.2	$0.2	($0.4)	($0.1)	$0.5	$4.6	1,810	940
3	Sherman Avenue	Transformer	AECO	$4.6	$0.3	$0.1	$4.3	($0.2)	($0.1)	($0.0)	($0.1)	$4.2	1,196	60
4	East	Interface	500	$3.8	$1.4	$0.0	$2.4	($0.0)	($0.0)	($0.0)	($0.0)	$2.3	1,046	44
5	Wylie Ridge	Transformer	AP	$2.8	$1.1	$0.0	$1.7	$0.1	($0.1)	($0.0)	$0.2	$2.0	3,836	760
6	Graceton - Raphael Road	Line	BGE	($2.0)	($0.6)	($0.0)	($1.4)	($0.0)	$0.1	$0.0	($0.1)	($1.5)	2,324	830
7	Crete - St Johns Tap	Flowgate	MISO	$1.6	$0.4	$0.0	$1.1	$0.1	($0.0)	($0.0)	$0.1	$1.2	6,756	2,240
8	Shieldalloy - Vineland	Line	AECO	$3.9	$0.8	$0.2	$3.2	($1.4)	$0.5	($0.3)	($2.2)	$1.0	1,496	468
9	AP South	Interface	500	$1.5	$0.6	$0.1	$0.9	($0.0)	($0.1)	($0.1)	$0.0	$1.0	8,240	2,026
10	Dickerson - Quince Orchard	Line	Pepco	$1.4	$0.7	$0.0	$0.7	$0.0	($0.1)	($0.0)	$0.1	$0.8	284	152
11	South Mahwah - Waldwick	Line	PSEG	$0.9	$0.3	$0.1	$0.7	$0.0	($0.0)	($0.1)	$0.0	$0.7	10,538	988
12	East Frankfort - Crete	Line	ComEd	$0.6	$0.2	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	3,092	658
13	Orchard - Orchard Tap	Line	AECO	$1.0	$0.5	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	70	0
14	Plymouth Meeting - Whitpain	Line	PECO	$0.8	$0.4	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	412	144
15	Burnham - Munster	Flowgate	MISO	$0.6	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,304	0
37	Orchard	Transformer	AECO	$0.7	$0.4	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0
50	Corson	Transformer	AECO	$0.1	($0.0)	$0.0	$0.1	$0.4	$0.1	($0.0)	$0.2	$0.3	62	52
66	Carlls Corner - Sherman Ave	Line	AECO	$0.1	$0.0	$0.0	$0.1	($0.2)	$0.2	($0.0)	($0.4)	($0.3)	188	88
76	Churchtown	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	0	66
82	Carnegie - Tidd	Line	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,704	0

BGE Control Zone

Table G-10 BGE Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	$39.9	$27.8	$2.7	$14.8	$0.3	$0.3	($2.0)	($2.0)	$12.8	5,328	1,446
2	AP South	Interface	500	$21.3	$17.8	$1.6	$5.1	$0.8	($0.5)	($2.4)	($1.1)	$4.0	5,172	702
3	West	Interface	500	$14.1	$10.7	$0.5	$3.9	$0.1	($0.1)	($0.5)	($0.3)	$3.6	1,682	260
4	Bedington - Black Oak	Interface	500	$9.3	$7.8	$0.8	$2.3	$0.1	($0.2)	($0.3)	$0.0	$2.3	1,560	108
5	Loudoun - Gainsville	Line	Dominion	$4.3	$3.6	$0.2	$0.9	$0.0	($0.0)	($0.1)	($0.1)	$0.9	322	38
6	Clover	Transformer	Dominion	$5.0	$4.3	$0.5	$1.2	$0.3	($0.1)	($0.8)	($0.4)	$0.8	3,128	904
7	Green Street - Westport	Line	BGE	$1.0	$0.2	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	278	0
8	High Ridge - Howard	Line	BGE	$1.1	$0.4	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	104	0
9	Howard - Pumphrey	Line	Pepco	$1.4	$0.8	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	298	0
10	Hazelwood - Windy Edge	Line	BGE	$0.9	$0.2	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	80	0
11	Northwest	Other	BGE	$9.8	$6.1	$0.6	$4.4	($1.5)	$1.2	($1.1)	($3.7)	$0.7	1,168	804
12	Bcpep	Interface	Pepco	$2.7	$2.2	$0.2	$0.7	$0.0	($0.0)	($0.2)	($0.2)	$0.6	178	12
13	Rantoul - Rantoul Jct	Flowgate	MISO	$2.4	$2.1	$0.2	$0.6	$0.0	($0.0)	($0.1)	($0.0)	$0.5	4,072	630
14	Crete - St Johns Tap	Flowgate	MISO	$2.5	$2.1	$0.1	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	4,754	554
15	Stephenson - Stonewall	Line	AP	$1.6	$1.3	$0.1	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	538	42
20	Erdman - Monument St.	Line	BGE	$0.4	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	34	0
23	Conastone - Otter	Line	BGE	$2.3	$2.1	$0.3	$0.5	$0.1	$0.1	($0.3)	($0.3)	$0.3	490	350
24	Brandon Shores - Riverside	Line	BGE	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	208	6
29	Conastone - Northwest	Line	BGE	$0.5	$0.3	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	80	4
34	Graceton	Transformer	BGE	$0.3	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	($0.0)	$0.2	68	162

Table G-11 BGE Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$29.1	$21.1	$0.5	$8.5	$0.0	($0.1)	($0.0)	$0.1	$8.6	1,758	40
2	AP South	Interface	500	$58.6	$53.5	$1.7	$6.9	$1.4	($0.5)	($1.7)	$0.3	$7.1	8,240	2,026
3	Dickerson - Quince Orchard	Line	Pepco	$15.2	$11.0	$0.1	$4.3	$0.6	$0.4	($0.4)	($0.1)	$4.2	284	152
4	Wagner	Transformer	BGE	$4.2	$0.8	$0.1	$3.5	($0.1)	($0.6)	($0.3)	$0.2	$3.7	402	52
5	Graceton - Raphael Road	Line	BGE	$14.6	$11.0	$0.6	$4.2	($0.1)	$0.4	($0.7)	($1.2)	$3.1	2,324	830
6	Pumphrey	Transformer	Pepco	$4.9	$2.1	$0.2	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	486	0
7	5004/5005 Interface	Interface	500	$10.9	$8.4	$0.1	$2.6	$0.1	($0.2)	($0.1)	$0.2	$2.8	1,810	940
8	Wylie Ridge	Transformer	AP	$12.0	$10.3	$0.3	$2.0	$0.3	($0.1)	($0.2)	$0.2	$2.2	3,836	760
9	Conastone - Graceton	Line	BGE	$5.3	$3.6	$0.2	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	236	0
10	Crete - St Johns Tap	Flowgate	MISO	$7.9	$6.7	$0.2	$1.4	$0.3	$0.1	($0.2)	$0.0	$1.5	6,756	2,240
11	High Ridge - Howard	Line	BGE	$3.2	$1.0	$0.2	$2.3	($0.7)	($0.2)	($0.4)	($0.9)	$1.4	204	92
12	Glenarm - Windy Edge	Line	BGE	$5.3	$3.6	$0.3	$2.0	($0.0)	$0.3	($0.2)	($0.6)	$1.4	1,366	316
13	Brandon Shores - Riverside	Line	BGE	$0.9	($0.4)	$0.1	$1.3	($0.1)	($0.1)	($0.1)	($0.1)	$1.2	276	18
14	Bedington - Black Oak	Interface	500	$9.0	$7.9	$0.1	$1.2	($0.0)	($0.0)	($0.0)	($0.0)	$1.2	1,358	14
15	East	Interface	500	($4.5)	($3.8)	($0.2)	($0.9)	($0.0)	$0.1	$0.0	($0.1)	($1.0)	1,046	44
16	Erdman - Monument St.	Line	BGE	$1.0	$0.2	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	14	0
17	Riverside	Other	BGE	$2.8	$0.0	$0.1	$2.9	($0.1)	$2.8	($0.9)	($3.7)	($0.8)	792	262
19	Howard - Pumphrey	Line	BGE	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.9)	($0.8)	($0.6)	($0.6)	0	120
27	Northwest	Other	BGE	$0.7	$0.5	$0.0	$0.3	($0.1)	$0.3	($0.2)	($0.6)	($0.4)	90	206
29	Chesaco Park - Gray Manor	Line	BGE	$0.3	($0.0)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	104	0

DPL Control Zone

Table G-12 DPL Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	($10.7)	($4.3)	($0.8)	($7.2)	($0.2)	($0.6)	$0.6	$1.0	($6.2)	5,328	1,446
2	West	Interface	500	$7.4	$3.6	$0.3	$4.0	$0.1	$0.2	($0.2)	($0.3)	$3.7	1,682	260
3	Mardela - Vienna	Line	DPL	$3.6	$1.3	$0.4	$2.7	($4.2)	($0.1)	($2.1)	($6.2)	($3.4)	412	252
4	Lumspond - Reybold	Line	DPL	$2.3	$0.3	$0.1	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	504	0
5	Longwood - Wye Mills	Line	DPL	$3.5	$0.9	$0.2	$2.7	($0.5)	$0.0	($0.3)	($0.8)	$1.9	1,308	90
6	Kenney - Stockton	Line	DPL	$11.7	$3.5	$1.1	$9.3	($6.3)	$1.6	($3.2)	($11.0)	($1.7)	1,368	982
7	Cedar Creek - Red Lion	Line	DPL	$2.0	$0.4	$0.2	$1.8	($0.1)	$0.0	($0.1)	($0.2)	$1.6	450	26
8	East	Interface	500	$2.1	$0.7	$0.0	$1.5	($0.0)	$0.1	($0.0)	($0.1)	$1.4	418	10
9	Church - Townsend	Line	DPL	$2.2	$0.3	$0.3	$2.2	($0.3)	$0.4	($0.4)	($1.0)	$1.1	672	76
10	Buxmont - Whitpain	Line	PECO	$2.1	$1.2	$0.1	$1.0	($0.0)	$0.0	($0.0)	($0.0)	$1.0	638	6
11	AP South	Interface	500	$2.1	$0.9	$0.2	$1.4	$0.1	$0.2	($0.3)	($0.4)	$1.0	5,172	702
12	Chichester - Eddystone	Line	PECO	($0.4)	($0.3)	($0.1)	($0.2)	($0.0)	($1.0)	$0.2	$1.2	$1.0	102	90
13	Easton - Trappe	Line	DPL	$1.0	$0.3	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	548	0
14	Bedington - Black Oak	Interface	500	$1.4	$0.7	$0.2	$0.8	$0.0	$0.0	($0.1)	($0.1)	$0.7	1,560	108
15	New Church - Piney Grove	Line	DPL	$0.3	$0.0	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,114	0
16	North Salisbury - Rockawalkin	Line	DPL	$0.7	$0.3	$0.0	$0.5	($0.4)	$0.3	($0.3)	($1.0)	($0.5)	124	32
19	Talbot - Tanyard	Line	DPL	$2.1	$0.7	($0.0)	$1.4	($0.6)	$0.2	($0.0)	($0.8)	$0.5	346	132
20	Preston - Tanyard	Line	DPL	$0.6	$0.1	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	716	0
22	Easton - Easton Tap	Line	DPL	$0.8	$0.2	$0.0	$0.6	($0.1)	$0.1	($0.0)	($0.2)	$0.5	618	0
23	Mount Hermon - North	Line	DPL	$0.5	$0.1	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	62	6

Table G-13 DPL Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$14.0	$5.0	$0.1	$9.1	$0.3	$0.8	($0.3)	($0.8)	$8.3	1,810	940
2	West	Interface	500	$16.2	$8.8	$0.2	$7.6	$0.0	$0.0	($0.0)	$0.0	$7.6	1,758	40
3	Wylie Ridge	Transformer	AP	$5.7	$1.6	$0.1	$4.1	$0.1	$0.2	($0.0)	($0.1)	$4.0	3,836	760
4	East	Interface	500	$7.0	$3.1	($0.0)	$3.8	($0.0)	$0.1	($0.0)	($0.1)	$3.8	1,046	44
5	AP South	Interface	500	$4.1	$1.5	$0.2	$2.9	$0.0	$0.3	($0.3)	($0.6)	$2.3	8,240	2,026
6	Crete - St Johns Tap	Flowgate	MISO	$3.0	$0.8	$0.0	$2.3	$0.1	$0.3	($0.0)	($0.2)	$2.0	6,756	2,240
7	Graceton - Raphael Road	Line	BGE	($3.9)	($1.4)	($0.3)	($2.8)	($0.1)	($0.6)	$0.2	$0.8	($2.0)	2,324	830
8	New Church - Piney Grove	Line	DPL	$2.1	$0.4	$0.1	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	980	0
9	Plymouth Meeting - Whitpain	Line	PECO	$2.3	$1.0	$0.0	$1.3	$0.1	$0.1	($0.1)	($0.0)	$1.3	412	144
10	Longwood - Wye Mills	Line	DPL	$1.5	$0.4	$0.1	$1.2	($0.0)	$0.0	($0.0)	($0.0)	$1.2	1,776	6
11	Burnham - Munster	Flowgate	MISO	$1.1	$0.4	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	2,304	0
12	East Frankfort - Crete	Line	ComEd	$1.1	$0.3	$0.0	$0.8	$0.0	$0.1	$0.0	($0.1)	$0.7	3,092	658
13	Glenarm - Windy Edge	Line	BGE	($1.1)	($0.4)	($0.0)	($0.8)	($0.0)	($0.1)	$0.0	$0.1	($0.7)	1,366	316
14	Bedington - Black Oak	Interface	500	$0.9	$0.2	$0.0	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.6	1,358	14
15	Dickerson - Quince Orchard	Line	Pepco	$2.5	$1.6	$0.0	$1.0	$0.1	$0.4	($0.0)	($0.4)	$0.6	284	152
22	Hallwood - Oak Hall	Line	DPL	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	362	0
24	Mardela - Vienna	Line	DPL	$0.4	$0.1	$0.0	$0.4	($0.2)	$0.4	($0.1)	($0.8)	($0.4)	310	52
28	Easton - Trappe	Line	DPL	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	248	0
46	Bellehaven - Tasley	Line	DPL	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,222	0
52	Oak Hall	Transformer	DPL	$0.2	$0.0	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	10	0

JCPL Control Zone

Table G-14 JCPL Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$8.4	$4.2	$0.1	$4.3	($0.0)	$0.1	($0.1)	($0.2)	$4.1	1,682	260
2	Graceton - Raphael Road	Line	BGE	($11.4)	($7.7)	($0.4)	($4.0)	$0.4	$0.1	$0.3	$0.5	($3.5)	5,328	1,446
3	East	Interface	500	$1.9	$0.9	$0.0	$1.1	($0.0)	($0.0)	($0.0)	($0.0)	$1.1	418	10
4	Red Oak - Sayreville	Line	JCPL	($0.1)	($1.2)	($0.2)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	2,888	0
5	Bridgewater - Middlesex	Line	PSEG	$1.6	$0.7	$0.2	$1.1	$0.0	$0.3	$0.1	($0.2)	$0.9	1,694	62
6	5004/5005 Interface	Interface	500	$1.3	$0.7	$0.0	$0.7	$0.1	($0.0)	($0.0)	$0.0	$0.7	382	256
7	Northwest	Other	BGE	($2.7)	($2.1)	($0.0)	($0.7)	$0.0	$0.1	$0.1	$0.0	($0.6)	1,168	804
8	Harwood - Susquehanna	Line	PPL	$0.8	$0.3	$0.1	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	772	40
9	Roseland - Whippany	Line	PSEG	($0.9)	($0.4)	($0.0)	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	1,794	0
10	Loudoun - Gainsville	Line	Dominion	$1.2	$0.7	$0.0	$0.5	$0.0	$0.0	($0.0)	$0.0	$0.5	322	38
11	Clover	Transformer	Dominion	$1.1	$0.7	$0.0	$0.5	$0.1	$0.0	($0.1)	($0.0)	$0.5	3,128	904
12	Franklin - Vernon	Line	JCPL	($0.0)	$0.0	$0.5	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,420	0
13	Kittatiny - Newton	Line	JCPL	$0.4	($0.0)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	56	0
14	Crete - St Johns Tap	Flowgate	MISO	$1.0	$0.5	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.4	4,754	554
15	Rantoul - Rantoul Jct	Flowgate	MISO	$1.0	$0.6	$0.0	$0.4	$0.0	($0.0)	($0.0)	($0.0)	$0.4	4,072	630
25	Newton - Illiff	Line	JCPL	$0.2	($0.0)	($0.0)	$0.2	($0.0)	$0.0	$0.0	$0.0	$0.2	570	18
47	Gilbert - Glen Gardner	Line	JCPL	$0.2	$0.0	$0.0	$0.2	$0.1	$0.2	($0.0)	($0.1)	$0.1	42	36
60	Franklin - West Wharton	Line	JCPL	($0.0)	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	964	0
75	Atlantic - Larrabee	Line	JCPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	214	0
201	Montville - Roseland	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0

Table G-15 JCPL Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$19.0	$8.6	$0.1	$10.5	$0.9	$0.2	($0.1)	$0.6	$11.0	1,810	940
2	West	Interface	500	$19.8	$11.4	$0.1	$8.6	($0.0)	($0.0)	($0.0)	($0.0)	$8.5	1,758	40
3	Red Oak - Sayreville	Line	JCPL	($1.3)	($5.3)	($0.1)	$3.9	$0.0	$0.1	$0.0	($0.1)	$3.8	3,504	22
4	South Mahwah - Waldwick	Line	PSEG	$6.7	$3.0	$0.3	$4.1	($0.1)	($0.0)	($0.3)	($0.4)	$3.7	10,538	988
5	Wylie Ridge	Transformer	AP	$6.5	$3.0	$0.0	$3.5	$0.1	$0.1	($0.0)	($0.0)	$3.5	3,836	760
6	East	Interface	500	$6.7	$3.7	$0.0	$3.0	($0.1)	$0.0	($0.0)	($0.1)	$2.9	1,046	44
7	Bridgewater - Middlesex	Line	PSEG	$4.6	$1.8	$0.2	$3.0	($0.2)	$0.2	($0.5)	($0.9)	$2.1	1,108	126
8	Cedar Grove - Roseland	Line	PSEG	($3.1)	($1.2)	($0.1)	($2.1)	$0.0	$0.0	$0.0	$0.0	($2.0)	1,842	78
9	Crete - St Johns Tap	Flowgate	MISO	$3.6	$1.8	$0.0	$1.8	$0.1	$0.1	($0.0)	($0.0)	$1.8	6,756	2,240
10	Dickerson - Quince Orchard	Line	Pepco	$2.6	$1.6	$0.0	$1.0	$0.4	$0.1	($0.0)	$0.3	$1.3	284	152
11	Graceton - Raphael Road	Line	BGE	($4.1)	($2.7)	($0.1)	($1.5)	$0.4	$0.1	$0.1	$0.4	($1.2)	2,324	830
12	East Windsor - Smithburg	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.9	($0.0)	$0.0	$0.9	$0.9	0	18
13	Susquehanna	Transformer	PPL	$1.2	$0.4	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	240	0
14	East Frankfort - Crete	Line	ComEd	$1.4	$0.8	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	3,092	658
15	Atlantic - Larrabee	Line	JCPL	$0.4	($0.2)	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.6	170	2
42	Flanders - W. Wharton	Line	JCPL	$0.0	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	550	0
49	Kilmer - Sayreville	Line	JCPL	$0.3	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	186	0
63	Deep Run - Englishtown	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.1)	($0.1)	0	28
165	Lakewood - Larrabee	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
178	Kittatiny - Newton	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0

Met-Ed Control Zone

Table G-16 Met-Ed Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Hunterstown	Transformer	Met-Ed	$3.8	$0.4	$0.1	$3.6	($0.1)	$0.0	($0.0)	($0.1)	$3.4	1,396	136
2	Graceton - Raphael Road	Line	BGE	($10.5)	($13.5)	($0.3)	$2.8	$0.2	$0.2	$0.2	$0.2	$3.0	5,328	1,446
3	West	Interface	500	$6.1	$7.9	$0.8	($1.0)	$0.0	$0.1	($0.4)	($0.5)	($1.5)	1,682	260
4	Northwest	Other	BGE	($2.5)	($4.0)	($0.1)	$1.4	$0.2	$0.3	$0.1	$0.1	$1.5	1,168	804
5	Conemaugh - Hunterstown	Line	500	$0.3	$0.6	$0.1	($0.2)	($0.0)	$0.0	($1.1)	($1.1)	($1.3)	76	234
6	Gardners - Texas East	Line	Met-Ed	$0.5	($0.5)	$0.0	$1.0	($0.1)	$0.1	($0.0)	($0.2)	$0.8	1,186	74
7	Middletown Jctn. - Middletown Jctn.	Other	Met-Ed	$0.7	($0.0)	$0.0	$0.8	($0.0)	$0.0	$0.0	($0.1)	$0.7	94	14
8	Carlisle Pike - Gardners	Line	PENELEC	$0.5	$0.1	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	482	0
9	Dillsburg - Gardners	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	($0.0)	($0.4)	($0.4)	0	78
10	Three Mile Island	Transformer	Met-Ed	$0.9	$1.1	$0.0	($0.2)	($0.0)	$0.0	($0.2)	($0.2)	($0.4)	324	110
11	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.2	$0.0	$0.2	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	1,040	0
12	Smith Jct - Smith St.	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.3)	($0.3)	($0.3)	6	14
13	Graceton - Safe Harbor	Line	BGE	($0.7)	($0.9)	($0.1)	$0.1	$0.1	$0.1	$0.2	$0.2	$0.3	438	194
14	Buxmont - Whitpain	Line	PECO	($2.1)	($2.1)	($0.3)	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	638	6
15	Jackson - North Hanover	Line	Met-Ed	$0.3	($0.0)	$0.0	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.3	108	42
16	Middletown Jct	Transformer	Met-Ed	$0.4	($0.0)	$0.1	$0.5	$0.0	$0.0	($0.2)	($0.2)	$0.3	268	32
17	Jackson - Three Mile Island	Line	Met-Ed	$0.1	($0.1)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	90	0
22	Jackson - TMI	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.2)	($0.2)	0	54
26	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.1	($0.1)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	68	0
28	Ironwood - South Lebanon	Line	Met-Ed	$0.0	($0.2)	($0.0)	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	134	0

Table G-17 Met-Ed Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$10.9	$15.5	$0.1	($4.6)	$0.0	$0.0	($0.0)	($0.0)	($4.6)	1,758	40
2	Cly - Collins	Line	Met-Ed	$1.9	($1.3)	$0.1	$3.3	($0.5)	$0.4	($0.0)	($0.9)	$2.3	710	324
3	Wylie Ridge	Transformer	AP	$4.4	$6.3	$0.1	($1.8)	$0.1	($0.0)	($0.0)	$0.1	($1.7)	3,836	760
4	Hunterstown	Transformer	Met-Ed	$1.6	$0.0	$0.0	$1.5	$0.0	$0.0	($0.0)	$0.0	$1.5	164	18
5	Crete - St Johns Tap	Flowgate	MISO	$2.4	$3.4	($0.0)	($1.0)	$0.1	($0.0)	($0.0)	$0.1	($0.9)	6,756	2,240
6	Graceton - Raphael Road	Line	BGE	($3.3)	($4.6)	($0.2)	$1.1	($0.1)	$0.2	$0.1	($0.2)	$0.9	2,324	830
7	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.4	($0.7)	$0.0	$1.1	($0.1)	$0.1	($0.1)	($0.4)	$0.7	62	30
8	East	Interface	500	$0.4	($0.2)	($0.1)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,046	44
9	Carlisle Pike - Roxbury	Line	PENELEC	$0.6	$0.1	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	268	8
10	Dickerson - Quince Orchard	Line	Pepco	$1.3	$1.9	$0.0	($0.5)	$0.2	$0.1	($0.0)	$0.1	($0.5)	284	152
11	East Frankfort - Crete	Line	ComEd	$0.9	$1.3	$0.0	($0.4)	$0.0	($0.0)	($0.0)	$0.0	($0.4)	3,092	658
12	Burnham - Munster	Flowgate	MISO	$1.0	$1.4	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	2,304	0
13	Conastone - Graceton	Line	BGE	$0.1	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	236	0
14	Glenarm - Windy Edge	Line	BGE	($1.1)	($1.4)	($0.0)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.3	1,366	316
15	Susquehanna	Transformer	PPL	$0.3	($0.0)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	240	0
20	Glendon - Hosensack	Line	Met-Ed	$0.1	($0.1)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	162	2
28	Hunterstown - Lincoln	Line	Met-Ed	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	220	16
30	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	74	0
37	Cly - Newberry	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
69	Manor - Safe Harbor	Line	Met-Ed	($0.1)	($0.1)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	14	6

PECO Control Zone

Table G-18 PECO Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	($28.8)	($42.0)	($0.3)	$12.9	$0.3	$0.3	$0.2	$0.2	$13.1	5,328	1,446
2	West	Interface	500	$18.8	$25.4	$0.2	($6.4)	($0.1)	$0.3	($0.1)	($0.5)	($6.9)	1,682	260
3	Northwest	Other	BGE	($6.5)	($10.5)	($0.1)	$3.9	$0.3	$0.3	$0.1	$0.1	$4.0	1,168	804
4	Plymouth Meeting - Whitpain	Line	PECO	$5.8	$2.1	$0.1	$3.8	($0.1)	$0.8	($0.0)	($0.9)	$2.9	230	88
5	AP South	Interface	500	$4.4	$6.9	$0.1	($2.3)	($0.0)	$0.2	($0.2)	($0.4)	($2.7)	5,172	702
6	Buxmont - Whitpain	Line	PECO	$8.6	$6.5	$0.1	$2.2	($0.0)	$0.0	($0.0)	($0.0)	$2.2	638	6
7	Tuna - Waneeta	Line	PECO	$1.8	$0.5	$0.0	$1.4	($0.1)	$0.0	($0.1)	($0.2)	$1.2	282	62
8	Crete - St Johns Tap	Flowgate	MISO	$2.3	$3.5	$0.0	($1.1)	$0.0	($0.0)	($0.0)	($0.0)	($1.1)	4,754	554
9	Three Mile Island	Transformer	Met-Ed	($1.5)	($2.7)	($0.0)	$1.1	($0.0)	$0.1	$0.1	($0.0)	$1.1	324	110
10	5004/5005 Interface	Interface	500	$2.4	$3.3	$0.0	($0.9)	$0.0	$0.1	($0.1)	($0.2)	($1.0)	382	256
11	Bedington - Black Oak	Interface	500	$3.2	$4.3	$0.1	($0.9)	$0.0	$0.1	($0.1)	($0.1)	($1.0)	1,560	108
12	East	Interface	500	$4.5	$3.5	$0.0	$1.0	($0.0)	$0.1	($0.0)	($0.1)	$0.9	418	10
13	Emilie	Transformer	PECO	($0.5)	($1.9)	$0.0	$1.4	$0.0	$0.4	($0.1)	($0.5)	$0.9	2,064	388
14	Conastone - Otter	Line	BGE	($1.6)	($2.6)	($0.0)	$1.0	$0.0	$0.1	$0.0	($0.1)	$0.9	490	350
15	Central	Interface	500	$1.8	$2.6	$0.0	($0.8)	$0.0	$0.0	$0.0	($0.0)	($0.8)	428	4
16	Bala - Plymouth Meeting	Line	PECO	$1.4	$0.6	($0.0)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	38	0
19	Cromby	Transformer	PECO	$0.6	($0.0)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	220	0
21	Conastone - Peach Bottom	Line	PECO	($0.0)	($0.0)	($0.0)	$0.0	$0.5	$1.2	$0.0	($0.7)	($0.6)	36	20
22	Chichester - Eddystone	Line	PECO	$0.7	$0.1	$0.1	$0.7	$0.1	$0.1	($0.1)	($0.1)	$0.6	102	2
30	Peachbottom	Transformer	PECO	$0.2	($0.2)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	40	10

Table G-19 PECO Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$38.1	$45.9	$0.1	($7.6)	($0.0)	($0.0)	($0.0)	$0.0	($7.6)	1,758	40
2	Plymouth Meeting - Whitpain	Line	PECO	$11.1	$3.2	$0.0	$7.9	($0.3)	($0.0)	($0.1)	($0.4)	$7.6	412	144
3	East	Interface	500	$14.2	$8.9	$0.1	$5.4	($0.1)	$0.1	($0.0)	($0.2)	$5.2	1,046	44
4	Cromby	Transformer	PECO	$6.4	$0.6	$0.0	$5.8	($0.7)	$0.4	($0.0)	($1.1)	$4.7	756	304
5	Bryn Mawr - Plymouth Meeting	Line	PECO	$6.5	$2.0	$0.0	$4.4	($0.1)	($0.1)	$0.0	$0.0	$4.5	568	8
6	Graceton - Raphael Road	Line	BGE	($9.8)	($13.9)	($0.1)	$3.9	$0.5	$0.1	$0.1	$0.6	$4.5	2,324	830
7	AP South	Interface	500	$7.6	$11.8	$0.1	($4.0)	($0.2)	$0.1	($0.1)	($0.4)	($4.4)	8,240	2,026
8	5004/5005 Interface	Interface	500	$36.1	$38.8	$0.2	($2.5)	($0.6)	$1.0	($0.1)	($1.8)	($4.3)	1,810	940
9	Wylie Ridge	Transformer	AP	$14.0	$16.8	$0.1	($2.7)	($0.1)	$0.0	($0.1)	($0.1)	($2.8)	3,836	760
10	Bradford - Planebrook	Line	PECO	$2.4	($0.1)	$0.0	$2.5	$0.1	$0.3	$0.0	($0.2)	$2.3	242	86
11	Crete - St Johns Tap	Flowgate	MISO	$7.6	$9.5	$0.0	($1.9)	$0.0	$0.2	($0.0)	($0.2)	($2.1)	6,756	2,240
12	Dickerson - Quince Orchard	Line	Pepco	$5.9	$7.5	$0.0	($1.5)	$0.2	$0.5	($0.0)	($0.3)	($1.8)	284	152
13	Bala - Plymouth Meeting	Line	PECO	$2.6	$0.8	($0.0)	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	152	0
14	Conastone - Graceton	Line	BGE	($0.6)	($2.1)	($0.0)	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	236	0
15	Chichester	Transformer	PECO	$1.5	$0.1	$0.0	$1.5	($0.0)	$0.0	($0.0)	($0.1)	$1.4	118	8
16	Limerick	Transformer	PECO	$2.1	$0.7	($0.0)	$1.4	($0.0)	$0.0	($0.0)	($0.0)	$1.4	60	10
26	Eddystone - Saville	Line	PECO	$0.6	($0.0)	$0.0	$0.6	$0.0	$0.1	$0.0	($0.0)	$0.6	136	32
27	Emilie	Transformer	PECO	($0.2)	($0.8)	($0.0)	$0.7	$0.1	$0.3	$0.0	($0.2)	$0.5	648	306
32	Eddington - Holmesburg	Line	PECO	($0.0)	($0.4)	($0.0)	$0.4	($0.1)	$0.7	($0.0)	($0.8)	($0.4)	482	356
36	Blue Grass - Byberry	Line	PECO	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	116	0

PENELEC Control Zone

Table G-20 PENELEC Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	($5.6)	($12.9)	($0.5)	$6.8	$0.1	$0.7	$0.3	($0.3)	$6.5	1,682	260
2	AP South	Interface	500	($11.0)	($14.9)	($0.2)	$3.7	$0.9	$0.0	$0.3	$1.2	$4.9	5,172	702
3	Graceton - Raphael Road	Line	BGE	($9.5)	($11.7)	($0.1)	$2.1	$0.4	($0.1)	$0.0	$0.6	$2.8	5,328	1,446
4	Hooversville	Transformer	PENELEC	$6.7	$4.0	($0.0)	$2.7	$0.0	$0.0	($0.0)	($0.0)	$2.7	266	20
5	Hunterstown	Transformer	Met-Ed	($0.9)	($2.7)	($0.0)	$1.7	$0.0	($0.4)	$0.0	$0.4	$2.1	1,396	136
6	Johnstown	Transformer	PENELEC	$4.1	$2.6	$0.2	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	32	0
7	5004/5005 Interface	Interface	500	($0.9)	($2.5)	($0.1)	$1.4	$0.5	$0.7	$0.3	$0.1	$1.6	382	256
8	Bedington - Black Oak	Interface	500	($4.1)	($5.6)	$0.0	$1.4	$0.0	$0.1	$0.0	($0.0)	$1.4	1,560	108
9	East Sayre - North Waverly	Line	PENELEC	$1.9	$1.1	$0.4	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	2,840	0
10	Seward	Transformer	PENELEC	$1.8	$0.9	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	156	0
11	Keystone - Shelocta	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	($1.6)	($1.2)	($0.4)	($0.9)	($0.9)	8	10
12	Northwest	Other	BGE	($2.1)	($2.0)	$0.1	($0.1)	$0.3	($0.6)	($0.0)	$0.9	$0.9	1,168	804
13	Butler - Karns City	Line	AP	$2.9	$2.1	$0.1	$0.9	($0.0)	($0.0)	($0.0)	($0.0)	$0.8	686	18
14	Garretts Run - Kiski Valley	Line	AP	$3.6	$2.7	$0.1	$1.0	($0.1)	$0.0	($0.1)	($0.2)	$0.8	840	206
15	Crete - St Johns Tap	Flowgate	MISO	$2.3	$2.8	$0.1	($0.3)	($0.1)	$0.2	($0.0)	($0.3)	($0.6)	4,754	554
16	Altoona - Bear Rock	Line	PENELEC	($0.3)	($0.8)	($0.0)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	56	6
21	Laurel Lake - Tiffany	Line	PENELEC	$0.5	$0.1	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	892	0
23	Blairsville East	Transformer	PENELEC	($1.7)	($2.0)	($0.1)	$0.1	$0.2	$0.0	$0.1	$0.2	$0.3	390	20
24	Garrett - Garrett Tap	Line	PENELEC	$1.7	$1.4	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	164	16
27	East Towanda - Hillside	Line	PENELEC	$0.3	$0.1	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	616	0

Table G-21 PENELEC Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($14.9)	($39.4)	($1.7)	$22.8	$1.7	$3.0	$2.5	$1.3	$24.1	1,810	940
2	AP South	Interface	500	($38.8)	($54.6)	($0.4)	$15.5	$2.7	$0.7	$0.9	$2.9	$18.4	8,240	2,026
3	West	Interface	500	($11.1)	($26.8)	($1.4)	$14.3	$0.0	$0.1	$0.1	$0.0	$14.3	1,758	40
4	Wylie Ridge	Transformer	AP	$8.1	$20.0	$0.8	($11.1)	($0.6)	($0.4)	($0.4)	($0.6)	($11.7)	3,836	760
5	Crete - St Johns Tap	Flowgate	MISO	$7.4	$10.0	$0.1	($2.5)	($0.3)	$0.2	($0.1)	($0.6)	($3.1)	6,756	2,240
6	Altoona - Bear Rock	Line	PENELEC	($2.8)	($5.5)	($0.1)	$2.6	$0.7	$0.6	$0.2	$0.2	$2.9	380	154
7	Johnstown - Seward	Line	PENELEC	$2.0	($0.6)	$0.0	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	102	0
8	Bedington - Black Oak	Interface	500	($5.1)	($7.5)	($0.1)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1,358	14
9	Butler - Karns City	Line	AP	$5.5	$3.9	$0.3	$2.0	($0.2)	$0.0	($0.1)	($0.3)	$1.7	782	116
10	Susquehanna	Transformer	PPL	$0.5	($1.3)	($0.1)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	240	0
11	Yukon	Transformer	AP	$0.9	($0.9)	($0.0)	$1.8	($0.0)	$0.2	$0.0	($0.2)	$1.6	750	180
12	East	Interface	500	($2.4)	($4.2)	($0.3)	$1.5	$0.0	$0.1	$0.1	$0.0	$1.5	1,046	44
13	Graceton - Raphael Road	Line	BGE	($3.1)	($3.8)	($0.1)	$0.6	$0.2	$0.1	$0.1	$0.2	$0.8	2,324	830
14	East Frankfort - Crete	Line	ComEd	$2.9	$3.6	$0.1	($0.6)	$0.0	$0.1	($0.1)	($0.2)	($0.8)	3,092	658
15	AEP - DOM	Interface	500	($2.4)	($3.1)	$0.0	$0.7	$0.1	$0.0	$0.0	$0.0	$0.8	3,578	370
17	Laurel Lake - Tiffany	Line	PENELEC	$0.7	$0.1	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	154	0
23	Seward	Transformer	PENELEC	$0.4	$0.2	$0.0	$0.2	($0.2)	$0.5	($0.0)	($0.8)	($0.5)	42	44
26	East Towanda - S.Troy	Line	PENELEC	$0.2	$0.1	$0.3	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,450	0
28	Hooversville - Scalp Level	Line	PENELEC	$2.9	$2.1	$0.1	$0.8	($0.2)	$0.1	($0.1)	($0.4)	$0.5	434	110
35	Handsome Lake - Wayne	Line	PENELEC	$0.2	($0.2)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0

Pepco Control Zone

Table G-22 Pepco Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	$30.7	$20.0	$1.6	$12.4	($0.4)	$0.9	($1.0)	($2.4)	$10.0	5,328	1,446
2	AP South	Interface	500	$28.4	$19.3	$1.4	$10.5	($0.8)	$0.8	($1.9)	($3.6)	$6.9	5,172	702
3	Bedington - Black Oak	Interface	500	$12.3	$8.7	$0.6	$4.2	$0.0	$0.3	($0.2)	($0.5)	$3.8	1,560	108
4	West	Interface	500	$9.1	$6.5	$0.3	$2.9	($0.1)	($0.0)	($0.1)	($0.2)	$2.6	1,682	260
5	Buzzard - Ritchie	Line	Pepco	$4.7	$2.0	$0.4	$3.1	($3.4)	($5.1)	($2.2)	($0.5)	$2.6	1,008	294
6	Potomac River	Transformer	Pepco	$3.1	$1.4	$0.2	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	1,074	0
7	Loudoun - Gainsville	Line	Dominion	$5.8	$4.2	$0.2	$1.8	($0.1)	$0.0	($0.1)	($0.2)	$1.6	322	38
8	Northwest	Other	BGE	$8.3	$5.7	$0.4	$3.0	($0.4)	$0.6	($0.6)	($1.6)	$1.4	1,168	804
9	Rantoul - Rantoul Jct	Flowgate	MISO	$2.6	$1.9	$0.7	$1.4	($0.0)	$0.0	($0.0)	($0.1)	$1.3	4,072	630
10	AEP - DOM	Interface	500	$3.5	$2.6	$0.2	$1.1	($0.1)	$0.0	($0.1)	($0.1)	$0.9	4,190	122
11	Crete - St Johns Tap	Flowgate	MISO	$2.6	$1.8	$0.2	$1.0	($0.0)	$0.0	($0.0)	($0.1)	$0.9	4,754	554
12	Clover	Transformer	Dominion	$6.3	$4.7	$0.5	$2.1	($0.3)	$0.3	($0.7)	($1.3)	$0.8	3,128	904
13	Potomac	Transformer	Pepco	$1.4	$1.1	$0.3	$0.7	($0.0)	($0.0)	($0.0)	($0.0)	$0.7	1,232	20
14	Burches Hill - Palmers Corner	Line	Pepco	$1.0	$0.4	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	742	0
15	Conastone - Otter	Line	BGE	$2.3	$1.4	$0.2	$1.0	($0.1)	($0.1)	($0.4)	($0.4)	$0.6	490	350
18	Bcpep	Interface	Pepco	$2.9	$1.8	$0.1	$1.2	($0.0)	$0.5	($0.1)	($0.7)	$0.5	178	12
22	Oak Grove - Ritchie	Line	Pepco	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	382	2
24	Dickerson - Quince Orchard	Line	Pepco	$0.3	$0.1	$0.0	$0.2	($0.2)	$0.3	($0.1)	($0.6)	($0.4)	28	34
26	Burtonsville - Sandy Springs	Line	Pepco	($0.3)	($0.2)	($0.0)	($0.1)	$0.3	$0.1	$0.3	$0.5	$0.4	102	0
36	Buzzard Point	Transformer	Pepco	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	60	0

Table G-23 Pepco Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$79.8	$58.9	$1.4	$22.2	($2.2)	($1.5)	($1.3)	($2.0)	$20.1	8,240	2,026
2	Dickerson - Quince Orchard	Line	Pepco	$27.8	$12.2	$0.2	$15.9	$0.5	$1.8	($0.2)	($1.5)	$14.4	284	152
3	West	Interface	500	$19.3	$13.3	$0.3	$6.2	($0.0)	($0.0)	($0.0)	$0.0	$6.3	1,758	40
4	Graceton - Raphael Road	Line	BGE	$11.4	$7.8	$0.1	$3.8	($0.2)	$0.0	($0.1)	($0.4)	$3.4	2,324	830
5	Wylie Ridge	Transformer	AP	$11.7	$8.6	$0.3	$3.5	($0.3)	($0.2)	($0.1)	($0.1)	$3.4	3,836	760
6	Bedington - Black Oak	Interface	500	$11.4	$8.4	$0.2	$3.2	($0.0)	($0.0)	($0.0)	$0.0	$3.2	1,358	14
7	Crete - St Johns Tap	Flowgate	MISO	$8.3	$5.8	$0.1	$2.7	($0.2)	($0.0)	($0.1)	($0.3)	$2.4	6,756	2,240
8	Danville - East Danville	Line	AEP	$7.3	$5.1	($0.0)	$2.2	($0.1)	($0.3)	$0.1	$0.2	$2.4	9,264	646
9	AEP - DOM	Interface	500	$7.4	$5.6	$0.1	$2.0	($0.1)	($0.1)	$0.0	$0.0	$2.0	3,578	370
10	5004/5005 Interface	Interface	500	$5.8	$4.1	$0.1	$1.7	($0.0)	($0.1)	($0.1)	($0.1)	$1.6	1,810	940
11	East	Interface	500	($5.1)	($3.9)	($0.1)	($1.3)	$0.0	$0.1	$0.0	($0.1)	($1.4)	1,046	44
12	Gore - Hampshire	Line	AP	$4.3	$3.1	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	1,654	0
13	East Frankfort - Crete	Line	ComEd	$3.4	$2.2	$0.1	$1.3	($0.0)	($0.0)	($0.1)	($0.1)	$1.2	3,092	658
14	Burnham - Munster	Flowgate	MISO	$3.3	$2.4	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	2,304	0
15	Glenarm - Windy Edge	Line	BGE	$3.5	$2.5	$0.1	$1.1	($0.1)	($0.1)	($0.1)	($0.1)	$1.0	1,366	316
28	Pumphrey	Transformer	Pepco	($1.5)	($1.1)	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	486	0
54	Burches Hill	Transformer	Pepco	$0.8	$0.5	$0.1	$0.4	$0.1	$0.0	($0.2)	($0.2)	$0.2	136	88
74	Buzzard - Ritchie	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	148	0
91	Burtonsville - Sandy Springs	Line	Pepco	($0.2)	($0.1)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	24	0
194	Dickerson - Pleasant View	Line	Pepco	$0.1	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	($0.1)	($0.0)	40	20

PPL Control Zone

Table G-24 PPL Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Harwood - Susquehanna	Line	PPL	$2.1	($2.3)	($0.1)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	772	40
2	Graceton - Raphael Road	Line	BGE	($26.5)	($30.7)	($0.7)	$3.5	($0.3)	$0.0	$0.5	$0.2	$3.7	5,328	1,446
3	Harwood - Siegfried	Line	PPL	$0.0	$0.0	$0.0	$0.0	($0.6)	$0.3	($0.4)	($1.3)	($1.3)	0	90
4	5004/5005 Interface	Interface	500	$3.1	$4.1	$0.3	($0.6)	$0.5	$0.3	($0.9)	($0.6)	($1.2)	382	256
5	Hummelstown - Steelton	Line	Met-Ed	$1.4	$0.4	$0.0	$1.0	$0.0	$0.0	($0.0)	$0.0	$1.0	80	4
6	Wescosville	Transformer	PPL	$1.9	$1.0	$0.0	$1.0	$0.1	$0.1	($0.0)	$0.0	$1.0	316	62
7	Three Mile Island	Transformer	Met-Ed	$0.4	($0.4)	$0.0	$0.9	$0.2	$0.1	($0.1)	$0.0	$0.9	324	110
8	Juniata	Transformer	PPL	$0.4	($0.1)	$0.2	$0.7	$0.2	($0.0)	($0.2)	$0.0	$0.7	598	76
9	Plymouth Meeting - Whitpain	Line	PECO	($1.1)	($1.5)	($0.1)	$0.3	($0.1)	($0.2)	$0.1	$0.2	$0.6	230	88
10	Palisades - Roosevelt	Flowgate	MISO	$1.6	$2.1	($0.0)	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	1,710	418
11	West	Interface	500	$16.8	$18.1	$0.7	($0.6)	$0.3	($0.2)	($0.3)	$0.2	($0.4)	1,682	260
12	Clover	Transformer	Dominion	$1.9	$2.3	$0.2	($0.2)	$0.1	$0.1	($0.2)	($0.2)	($0.4)	3,128	904
13	Benton Harbor - Palisades	Flowgate	MISO	$1.4	$1.8	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	1,680	142
14	Sunbury	Transformer	PPL	$0.1	$0.0	$0.3	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	1,104	2
15	Graceton - Safe Harbor	Line	BGE	($1.7)	($1.7)	($0.0)	$0.0	($0.3)	$0.3	$0.2	($0.4)	($0.4)	438	194
18	Buxmont - Hosensack	Line	PPL	($0.8)	($1.2)	($0.1)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	216	0
22	Mountain - Wasserot	Line	PPL	($0.0)	($0.0)	$0.3	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	840	0
24	Mountain	Transformer	PPL	$0.1	$0.0	$0.2	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	414	0
25	Martins Creek - Quarry	Line	PPL	($0.1)	($0.4)	($0.0)	$0.3	($0.0)	$0.0	$0.0	$0.0	$0.3	146	0
33	Quarry - Steel City	Line	PPL	$0.0	($0.2)	($0.0)	$0.2	($0.0)	($0.0)	$0.0	$0.0	$0.2	110	2

Table G-25 PPL Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$42.3	$53.4	$1.2	($10.0)	$1.8	$1.3	($0.8)	($0.2)	($10.2)	1,810	940
2	Susquehanna	Transformer	PPL	$16.5	$6.6	$0.2	$10.1	$0.0	$0.0	$0.0	$0.0	$10.1	240	0
3	West	Interface	500	$32.1	$38.0	$1.1	($4.8)	$0.0	($0.1)	($0.0)	$0.1	($4.7)	1,758	40
4	Harwood - Susquehanna	Line	PPL	$0.7	($3.0)	($0.1)	$3.7	($0.4)	$0.2	$0.1	($0.5)	$3.2	310	106
5	Graceton - Raphael Road	Line	BGE	($8.9)	($11.7)	($0.3)	$2.5	($0.1)	$0.1	$0.2	($0.0)	$2.5	2,324	830
6	Wylie Ridge	Transformer	AP	$14.0	$16.7	$0.4	($2.2)	$0.5	$0.1	($0.1)	$0.3	($1.9)	3,836	760
7	AP South	Interface	500	$0.4	($1.0)	$0.5	$1.8	$0.3	$0.1	($0.2)	$0.0	$1.9	8,240	2,026
8	Crete - St Johns Tap	Flowgate	MISO	$7.6	$9.5	$0.0	($1.9)	$0.4	$0.2	($0.0)	$0.2	($1.7)	6,756	2,240
9	Susquehanna	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	$0.1	($1.5)	($0.2)	$1.4	$1.4	0	104
10	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$1.0	$0.7	$0.0	$0.3	$0.4	($0.7)	($0.0)	$1.1	$1.4	62	30
11	Burnham - Munster	Flowgate	MISO	$3.0	$4.3	($0.0)	($1.3)	$0.0	$0.0	$0.0	$0.0	($1.3)	2,304	0
12	South Mahwah - Waldwick	Line	PSEG	$3.1	$3.9	$0.8	$0.0	$0.2	$0.3	($1.0)	($1.1)	($1.1)	10,538	988
13	East	Interface	500	($0.2)	($1.4)	($0.2)	$1.0	$0.0	$0.0	$0.1	$0.1	$1.0	1,046	44
14	Wescosville	Transformer	PPL	$1.6	$0.9	$0.0	$0.7	$0.3	$0.0	($0.0)	$0.3	$1.0	88	80
15	East Frankfort - Crete	Line	ComEd	$2.7	$3.6	$0.0	($0.9)	$0.0	($0.0)	($0.0)	$0.1	($0.8)	3,092	658
16	Juniata	Transformer	PPL	$0.8	$0.7	$0.1	$0.2	$0.3	$0.3	$0.6	$0.6	$0.7	266	32
50	Mountain	Transformer	PPL	$0.1	($0.2)	$0.0	$0.2	($0.2)	$0.1	($0.1)	($0.4)	($0.1)	134	90
51	Elroy	Transformer	PPL	$0.5	$0.6	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	424	0
65	Dauphin - Juniata	Line	PPL	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	8	0
66	Quarry - Steel City	Line	PPL	($0.0)	($0.1)	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	12	34

PSEG Control Zone

Table G-26 PSEG Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Leonia - New Milford	Line	PSEG	$3.0	$3.1	$2.9	$2.8	($0.4)	$0.3	($6.7)	($7.4)	($4.6)	2,696	292
2	Deans	Transformer	PSEG	$0.5	$0.1	$0.4	$0.8	($0.2)	$0.4	($2.5)	($3.0)	($2.3)	370	68
3	Hillsdale - New Milford	Line	PSEG	$1.9	$1.4	$2.4	$2.9	($0.0)	$1.2	($3.9)	($5.2)	($2.3)	2,696	544
4	Readington - Roseland	Line	PSEG	$5.0	$2.5	$0.7	$3.2	$0.0	$0.2	($1.1)	($1.3)	$1.8	2,166	190
5	Cedar Grove - Roseland	Line	PSEG	$0.9	$0.4	$0.3	$0.8	($0.2)	$0.6	($1.8)	($2.6)	($1.7)	1,096	120
6	Graceton - Raphael Road	Line	BGE	($24.9)	($26.4)	($1.3)	$0.1	$0.1	($0.7)	$0.8	$1.5	$1.6	5,328	1,446
7	Northwest	Other	BGE	($5.9)	($6.5)	($0.3)	$0.3	$0.3	($0.4)	$0.7	$1.3	$1.6	1,168	804
8	Maywood - Saddlebrook	Line	PSEG	$0.1	$0.1	($0.0)	($0.1)	($0.1)	$0.1	($1.2)	($1.3)	($1.4)	472	50
9	Farragut - Hudson	Line	PSEG	$0.8	$0.6	$0.9	$1.2	$0.0	$0.0	$0.2	$0.2	$1.4	1,028	8
10	Roseland - Whippany	Line	PSEG	$1.9	$1.0	$0.4	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	1,794	0
11	Bayway - Federal Square	Line	PSEG	$1.1	($0.4)	$0.4	$1.8	($0.1)	$0.1	($0.3)	($0.5)	$1.3	6,068	96
12	AP South	Interface	500	$1.6	$2.8	$0.4	($0.8)	$0.0	$0.1	($0.4)	($0.4)	($1.2)	5,172	702
13	Bergen - Hoboken	Line	PSEG	$0.0	$0.0	$0.1	$0.1	($0.0)	$0.5	($0.8)	($1.3)	($1.2)	146	140
14	Cedar Grove - Clifton	Line	PSEG	$0.3	$0.1	$0.1	$0.3	$0.0	$0.3	($1.1)	($1.3)	($1.0)	470	120
15	Conastone - Peach Bottom	Line	PECO	($0.0)	($0.0)	($0.0)	$0.0	$1.5	$0.7	$0.1	$0.9	$0.9	36	20
17	Athenia - East Rutherford	Line	PSEG	$1.1	$0.4	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	232	0
18	Hudson	Transformer	PSEG	$0.5	$0.3	$0.5	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,788	0
19	Bergen - Saddlebrook	Line	PSEG	$0.7	$0.5	$0.5	$0.7	$0.0	($0.0)	$0.0	$0.0	$0.7	2,488	28
20	Fairlawn - Saddlebrook	Line	PSEG	$0.1	$0.1	$0.2	$0.2	($0.2)	($0.0)	($0.7)	($0.8)	($0.7)	458	116
25	Roseland - West Caldwell	Line	PSEG	$0.9	$0.6	$0.3	$0.7	$0.0	$0.1	($0.0)	($0.1)	$0.5	1,002	0

Table G-27 PSEG Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	South Mahwah - Waldwick	Line	PSEG	$29.5	$14.6	($7.0)	$7.9	($1.9)	$3.9	($13.0)	($18.8)	($10.9)	10,538	988
2	Waldwick	Transformer	PSEG	$2.1	$1.1	$1.4	$2.4	($0.6)	$0.5	($7.6)	($8.7)	($6.4)	296	186
3	Cedar Grove - Roseland	Line	PSEG	$9.2	$3.9	$0.2	$5.5	($0.1)	$0.7	($0.2)	($0.9)	$4.6	1,842	78
4	AP South	Interface	500	($1.0)	$3.3	$1.5	($2.8)	$0.1	($0.2)	($1.6)	($1.2)	($4.0)	8,240	2,026
5	West	Interface	500	$36.3	$33.9	$1.4	$3.8	($0.1)	$0.1	($0.0)	($0.2)	$3.6	1,758	40
6	Bayway - Federal Square	Line	PSEG	$2.0	($0.6)	$0.2	$2.9	($0.0)	$0.0	($0.0)	($0.1)	$2.8	2,292	30
7	Branchburg - Readington	Line	PSEG	$3.6	$1.2	$0.3	$2.7	($0.1)	$0.4	($0.2)	($0.7)	$2.0	936	108
8	5004/5005 Interface	Interface	500	$33.3	$31.8	$1.5	$2.9	$1.4	$4.4	($1.7)	($4.7)	($1.8)	1,810	940
9	Susquehanna	Transformer	PPL	$1.5	$0.2	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	240	0
10	Roseland - Whippany	Line	PSEG	$2.5	$1.1	$0.3	$1.6	($0.0)	$0.0	($0.4)	($0.5)	$1.2	684	112
11	Plymouth Meeting - Whitpain	Line	PECO	($0.7)	$0.6	$0.0	($1.2)	$0.1	($0.1)	($0.0)	$0.1	($1.1)	412	144
12	Red Oak - Sayreville	Line	JCPL	$1.1	$0.1	$0.1	$1.1	($0.0)	$0.0	($0.0)	($0.0)	$1.1	3,504	22
13	Graceton - Raphael Road	Line	BGE	($8.6)	($8.9)	($0.5)	($0.2)	$0.2	($0.5)	$0.4	$1.2	$0.9	2,324	830
14	Wylie Ridge	Transformer	AP	$12.2	$12.4	$0.7	$0.5	$0.0	$1.0	($0.4)	($1.4)	($0.9)	3,836	760
15	Camden	Transformer	PSEG	$0.9	$0.2	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	840	0
16	Bridgewater - Middlesex	Line	PSEG	$0.5	$0.3	$0.1	$0.3	$0.0	$0.7	($0.4)	($1.1)	($0.8)	1,108	126
17	Hawthorn - Waldwick	Line	PSEG	$0.2	$0.1	$0.6	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,318	0
18	Roseland - West Caldwell	Line	PSEG	$1.5	$0.5	$0.1	$1.1	($0.0)	$0.3	($0.2)	($0.4)	$0.7	264	58
23	Montville - Roseland	Line	PSEG	$1.1	$0.6	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	126	0
24	Athenia - Saddlebrook	Line	PSEG	$0.9	$0.6	$0.3	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.6	2,812	8

RECO Control Zone

Table G-28 RECO Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	($0.6)	($0.0)	($0.0)	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	5,328	1,446
2	West	Interface	500	$0.4	$0.0	$0.0	$0.4	($0.0)	($0.0)	$0.0	($0.0)	$0.4	1,682	260
3	Hillsdale - New Milford	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	2,696	544
4	Northwest	Other	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	1,168	804
5	5004/5005 Interface	Interface	500	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	382	256
6	East	Interface	500	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	418	10
7	Roseland - Whippany	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,794	0
8	Readington - Roseland	Line	PSEG	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.1)	($0.1)	$0.1	2,166	190
9	Benton Harbor - Palisades	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	1,680	142
10	Palisades - Roosevelt	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	1,710	418
11	Rantoul - Rantoul Jct	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	4,072	630
12	Loudoun - Gainsville	Line	Dominion	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	322	38
13	Buxmont - Whitpain	Line	PECO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	638	6
14	Crete - St Johns Tap	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	4,754	554
15	Conastone - Peach Bottom	Line	PECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.1	36	20
373	Burns - Corporate Road	Line	RECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	8	0

Table G-29 RECO Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	South Mahwah - Waldwick	Line	PSEG	($1.5)	($0.6)	($0.0)	($0.9)	($0.0)	$1.0	$0.0	($1.0)	($1.9)	10,538	988
2	West	Interface	500	$1.0	$0.0	$0.0	$0.9	($0.0)	($0.0)	($0.0)	$0.0	$0.9	1,758	40
3	5004/5005 Interface	Interface	500	$0.9	$0.1	$0.0	$0.8	$0.0	($0.1)	($0.0)	$0.1	$0.9	1,810	940
4	Waldwick	Transformer	PSEG	($0.2)	($0.1)	($0.0)	($0.1)	($0.1)	$0.4	$0.0	($0.4)	($0.5)	296	186
5	East	Interface	500	$0.3	$0.0	$0.0	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	1,046	44
6	Wylie Ridge	Transformer	AP	$0.3	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	3,836	760
7	Cedar Grove - Roseland	Line	PSEG	$0.3	$0.1	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	1,842	78
8	Crete - St Johns Tap	Flowgate	MISO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	6,756	2,240
9	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	2,324	830
10	Dickerson - Quince Orchard	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.2	284	152
11	AP South	Interface	500	($0.2)	($0.0)	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.2)	8,240	2,026
12	Branchburg - Readington	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	936	108
13	Burnham - Munster	Flowgate	MISO	$0.1	$0.0	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2,304	0
14	Glenarm - Windy Edge	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	($0.0)	($0.1)	1,366	316
15	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	3,092	658

Western Region Congestion-Event Summaries

AEP Control Zone

Table G-30 AEP Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Monticello - East Winamac	Flowgate	MISO	$1.6	($14.6)	($2.1)	$14.2	$0.3	$1.5	($0.5)	($1.7)	$12.4	5,468	1,156
2	Breed - Wheatland	Flowgate	MISO	$0.9	($12.0)	($4.6)	$8.3	$0.3	$0.3	$3.1	$3.0	$11.3	5,642	856
3	AP South	Interface	500	($28.9)	($39.2)	($1.8)	$8.5	$2.0	$2.4	$2.8	$2.4	$11.0	5,172	702
4	Kammer	Transformer	AEP	$4.8	($2.8)	$1.4	$9.0	($0.2)	$0.0	($0.1)	($0.3)	$8.7	7,332	38
5	AEP - DOM	Interface	500	($3.9)	($14.3)	$0.6	$10.9	$0.7	$3.3	($0.6)	($3.1)	$7.8	4,190	122
6	Brues - West Bellaire	Line	AEP	$3.2	($0.3)	$0.7	$4.2	($0.1)	$0.1	($0.1)	($0.2)	$3.9	3,132	140
7	Kenova - Tri State	Line	AEP	$0.4	($3.4)	$0.1	$3.9	($0.0)	$0.1	$0.1	$0.0	$3.9	940	52
8	Cumberland - Bush	Flowgate	MISO	$1.0	($3.5)	($0.5)	$4.0	$0.1	$0.9	$0.5	($0.3)	$3.7	4,106	632
9	West	Interface	500	($23.8)	($26.9)	($0.4)	$2.7	$0.7	$0.8	$0.3	$0.3	$3.0	1,682	260
10	Sporn	Transformer	AEP	$0.3	($0.5)	$2.1	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	38,672	0
11	Big Sandy - Grangston	Line	AEP	$0.3	$0.0	$2.2	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	6,132	0
12	Bedington - Black Oak	Interface	500	($10.9)	($13.3)	($0.4)	$1.9	$0.2	$0.1	$0.2	$0.3	$2.2	1,560	108
13	Ruth - Turner	Line	AEP	$1.3	($1.0)	($0.1)	$2.2	$0.0	$0.1	($0.0)	($0.1)	$2.1	668	156
14	Belvidere - Woodstock	Line	ComEd	($0.1)	($0.1)	$0.3	$0.3	$0.0	$0.0	($2.4)	($2.4)	($2.1)	1,760	1,532
15	Benton Harbor - Palisades	Flowgate	MISO	($2.7)	($4.9)	($0.2)	$2.0	$0.1	$0.0	$0.0	$0.1	$2.1	1,680	142
21	Sullivan	Transformer	AEP	($0.2)	($1.5)	($0.3)	$1.0	$0.0	($0.0)	$0.2	$0.2	$1.3	1,704	100
23	Muskingum River - Waterford	Line	AEP	($0.6)	($1.9)	$0.8	$2.1	$0.0	$0.2	($0.8)	($1.0)	$1.2	1,324	82
26	Muskingum River	Transformer	AEP	$0.1	($0.6)	$0.4	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	1,454	0
29	Breed - Wheatland	Line	AEP	$0.2	($1.3)	($0.4)	$1.1	$0.0	($0.0)	$0.0	$0.0	$1.1	244	0
34	Michigan City - Laporte	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.5)	($0.0)	($0.6)	($1.1)	($1.0)	48	0

Table G-31 AEP Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($113.5)	($148.9)	($1.3)	$34.1	$3.7	$6.9	$2.3	($1.0)	$33.1	8,240	2,026
2	Belmont	Transformer	AP	$13.1	($15.0)	$4.9	$33.1	($2.0)	($0.3)	($3.9)	($5.6)	$27.5	8,750	998
3	AEP - DOM	Interface	500	($13.9)	($37.1)	$2.5	$25.7	$0.6	$1.5	($0.7)	($1.6)	$24.1	3,578	370
4	Brues - West Bellaire	Line	AEP	$21.7	$6.3	$1.9	$17.3	($2.1)	$1.7	($2.0)	($5.8)	$11.5	3,436	1,196
5	5004/5005 Interface	Interface	500	($65.3)	($76.4)	($0.8)	$10.3	$2.9	$3.9	$1.3	$0.3	$10.7	1,810	940
6	West	Interface	500	($56.9)	($68.0)	($0.6)	$10.4	$0.0	$0.1	$0.0	($0.0)	$10.4	1,758	40
7	Breed - Wheatland	Line	AEP	$1.2	($7.4)	($1.0)	$7.6	($0.0)	($0.0)	($0.0)	$0.0	$7.6	2,484	2
8	Michigan City - Laporte	Flowgate	MISO	$15.2	$8.9	$4.3	$10.6	($3.1)	($1.7)	($3.9)	($5.4)	$5.2	5,870	1,264
9	Kammer	Transformer	AEP	$5.5	($2.8)	$1.2	$9.4	($3.4)	($0.3)	($1.3)	($4.4)	$5.1	2,578	138
10	Wolfcreek	Transformer	AEP	($8.9)	($14.2)	$1.4	$6.7	($0.1)	$0.5	($1.2)	($1.9)	$4.8	5,122	452
11	Wylie Ridge	Transformer	AP	($42.9)	($49.0)	($1.3)	$4.8	$0.5	$1.3	$0.6	($0.2)	$4.6	3,836	760
12	Bedington - Black Oak	Interface	500	($16.5)	($20.8)	($0.1)	$4.2	$0.1	$0.0	$0.0	$0.0	$4.2	1,358	14
13	Danville - East Danville	Line	AEP	($30.1)	($29.9)	($5.4)	($5.6)	$1.1	$1.6	$1.9	$1.4	($4.1)	9,264	646
14	Cloverdale	Transformer	AEP	($4.5)	($8.8)	$0.4	$4.7	$0.2	$0.8	($0.0)	($0.7)	$4.1	1,402	250
15	Muskingum River	Transformer	AEP	($0.5)	($3.9)	$0.5	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	636	0
17	Marquis - Dept of Energy	Line	AEP	$0.1	($0.3)	$3.2	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,998	0
19	Muskingum River - East New Concord	Line	AEP	$0.7	($1.8)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	218	0
21	Jefferson - Clifty Creek	Line	AEP	($0.1)	($3.1)	($0.4)	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	582	0
23	Carbondale - Kanawha River	Line	AEP	($3.5)	($5.6)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	548	0
25	Muskingum River - Waterford	Line	AEP	($1.0)	($2.8)	$1.5	$3.3	$0.2	$0.8	($0.5)	($1.1)	$2.2	1,066	106

AP Control Zone

Table G-32 AP Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($6.0)	($28.8)	$0.3	$23.1	$1.8	$4.2	($0.7)	($3.2)	$19.9	5,172	702
2	Bedington - Black Oak	Interface	500	($1.7)	($9.8)	($0.5)	$7.6	$0.3	$0.5	$0.0	($0.1)	$7.5	1,560	108
3	West	Interface	500	($8.4)	($11.8)	($0.7)	$2.8	$0.1	$0.7	$0.4	($0.2)	$2.6	1,682	260
4	Belmont	Transformer	AP	$3.0	($0.3)	$0.3	$3.6	($0.1)	$0.7	($0.4)	($1.2)	$2.5	3,666	120
5	Stephenson - Stonewall	Line	AP	$1.4	($0.5)	($0.2)	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	538	42
6	AEP - DOM	Interface	500	($0.2)	($1.5)	$0.1	$1.3	($0.0)	$0.1	$0.4	$0.3	$1.6	4,190	122
7	Clover	Transformer	Dominion	$0.9	($0.2)	$1.1	$2.1	$0.2	$0.1	($1.4)	($1.2)	$0.9	3,128	904
8	Loudoun - Gainsville	Line	Dominion	$0.5	($0.3)	$0.1	$0.9	$0.0	$0.0	($0.1)	($0.0)	$0.9	322	38
9	Kammer	Transformer	AEP	$0.4	($0.3)	$0.3	$0.9	($0.0)	($0.0)	($0.0)	($0.0)	$0.9	7,332	38
10	Doubs - Mount Storm	Line	500	($0.1)	($0.8)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	160	0
11	Hunterstown	Transformer	Met-Ed	($0.1)	($0.8)	$0.1	$0.8	$0.0	$0.2	($0.1)	($0.2)	$0.6	1,396	136
12	Gardners - Texas East	Line	Met-Ed	$0.5	$0.1	$0.2	$0.6	$0.0	($0.0)	($0.1)	($0.0)	$0.6	1,186	74
13	Garretts Run - Kiski Valley	Line	AP	$0.1	($0.9)	($0.1)	$0.9	($0.2)	$0.2	$0.1	($0.3)	$0.6	840	206
14	Tiltonsville - Windsor	Line	AP	$0.8	$0.3	$0.1	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	1,464	14
15	Belvidere - Woodstock	Line	ComEd	($0.0)	($0.1)	$0.1	$0.1	($0.0)	($0.0)	($0.7)	($0.6)	($0.6)	1,760	1,532
17	Shaffer - Springdale	Line	AP	$0.0	($0.5)	($0.1)	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	410	112
20	Butler - Karns City	Line	AP	$0.4	$0.0	($0.0)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.4	686	18
24	All Dam - Kittanning	Line	AP	($0.0)	($0.4)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	250	90
25	Bedington - Marlowe	Line	AP	$0.1	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	80	0
28	Kingwood - Pruntytown	Line	AP	$0.3	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	124	0

Table G-33 AP Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($26.3)	($91.6)	($7.8)	$57.6	$5.5	$5.7	$6.5	$6.3	$63.9	8,240	2,026
2	Belmont	Transformer	AP	$34.3	$7.2	$0.9	$28.0	($2.4)	($3.3)	($0.6)	$0.3	$28.3	8,750	998
3	5004/5005 Interface	Interface	500	($20.2)	($29.7)	($3.8)	$5.7	$1.4	$1.7	$4.4	$4.0	$9.7	1,810	940
4	Bedington - Black Oak	Interface	500	($3.1)	($11.6)	($1.9)	$6.5	$0.0	$0.1	$0.1	$0.1	$6.6	1,358	14
5	Yukon	Transformer	AP	$4.4	$0.0	$0.2	$4.6	$0.2	$0.4	($0.1)	($0.3)	$4.3	750	180
6	AEP - DOM	Interface	500	($1.3)	($4.7)	($0.0)	$3.3	$0.1	$0.1	$0.3	$0.4	$3.7	3,578	370
7	Bedington	Transformer	AP	$1.2	($2.7)	($0.2)	$3.6	($0.1)	$0.6	$0.3	($0.4)	$3.2	464	206
8	Wylie Ridge	Transformer	AP	$6.0	$9.7	$3.7	($0.0)	($0.1)	($0.3)	($3.1)	($2.9)	($2.9)	3,836	760
9	West	Interface	500	($18.5)	($24.4)	($3.2)	$2.6	$0.1	$0.0	$0.1	$0.1	$2.8	1,758	40
10	Wolfcreek	Transformer	AEP	$5.7	$8.2	$1.0	($1.5)	($0.5)	($0.6)	($1.0)	($0.9)	($2.4)	5,122	452
11	Tiltonsville - Windsor	Line	AP	$2.6	$0.7	$0.3	$2.1	($0.2)	($0.0)	($0.2)	($0.4)	$1.7	2,036	144
12	Dickerson - Quince Orchard	Line	Pepco	($6.8)	($5.2)	($0.9)	($2.5)	($0.8)	($0.2)	$1.3	$0.8	($1.7)	284	152
13	Mount Storm	Line	AP	($0.4)	($1.9)	$0.2	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	162	0
14	Danville - East Danville	Line	AEP	$0.3	($1.1)	$0.2	$1.5	$0.1	$0.0	$0.0	$0.1	$1.6	9,264	646
15	Valley	Transformer	Dominion	($0.8)	($2.0)	($0.0)	$1.2	$0.3	$0.2	$0.1	$0.2	$1.4	438	196
16	Gore - Hampshire	Line	AP	($2.1)	($3.8)	($0.4)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	1,654	0
19	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.6	$1.1	($0.6)	($1.1)	($1.1)	0	218
21	Kingwood - Pruntytown	Line	AP	$0.8	($0.1)	$0.1	$0.9	($0.0)	($0.1)	($0.0)	($0.0)	$0.9	426	28
25	Hamilton - Weirton	Line	AP	$1.0	$0.3	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	304	6
26	Halfway - Marlowe	Line	AP	$0.5	($0.2)	$0.0	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	158	18

ATSI Control Zone

Table G-34 ATSI Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($22.4)	($20.9)	($0.3)	($1.8)	$0.4	$1.6	$0.4	($0.7)	($2.5)	5,172	702
2	Highland - Salt Springs	Line	ATSI	$2.2	($0.0)	($0.1)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	56	0
3	Lakeview - Ottawa	Line	ATSI	$1.2	($1.0)	$0.0	$2.2	$0.1	$0.2	($0.0)	($0.1)	$2.1	200	40
4	Bedington - Black Oak	Interface	500	($7.0)	($5.4)	($0.1)	($1.8)	$0.2	$0.1	$0.0	$0.0	($1.7)	1,560	108
5	West	Interface	500	($12.0)	($10.9)	($0.1)	($1.1)	$0.1	$0.4	$0.0	($0.2)	($1.3)	1,682	260
6	Crescent	Transformer	DLCO	($3.1)	($4.5)	($0.2)	$1.2	$0.0	$0.1	$0.0	($0.0)	$1.2	590	60
7	Rantoul - Rantoul Jct	Flowgate	MISO	$3.0	$2.5	$0.3	$0.9	($0.0)	($0.0)	$0.1	$0.1	$1.0	4,072	630
8	Niles - Evergreen	Line	ATSI	$1.4	$0.3	$0.0	$1.2	($0.2)	$0.1	$0.0	($0.2)	$0.9	330	58
9	Lemoyne - Bowling Green	Line	ATSI	$0.4	($0.1)	$0.0	$0.5	$1.6	$1.2	($0.0)	$0.4	$0.9	234	414
10	AEP - DOM	Interface	500	($3.8)	($3.3)	($0.1)	($0.5)	($0.0)	$0.2	$0.0	($0.2)	($0.7)	4,190	122
11	Clover	Transformer	Dominion	($3.1)	($2.6)	$0.1	($0.4)	$0.0	$0.1	($0.0)	($0.1)	($0.5)	3,128	904
12	Prairie State - W Mt. Vernon	Flowgate	MISO	$1.5	$1.3	$0.2	$0.5	$0.0	($0.0)	$0.0	$0.0	$0.5	2,966	2,022
13	Brookside - Troy	Line	ATSI	$0.3	$0.1	$0.0	$0.2	($0.4)	$0.2	($0.1)	($0.7)	($0.5)	222	62
14	Crete - St Johns Tap	Flowgate	MISO	$3.3	$3.0	$0.2	$0.5	($0.0)	($0.0)	($0.1)	($0.0)	$0.4	4,754	554
15	Rising	Flowgate	MISO	$0.6	$0.5	$0.0	$0.1	($0.0)	($0.0)	$0.2	$0.2	$0.4	816	726
21	Lemoyne	Transformer	ATSI	$0.0	$0.0	$0.0	$0.0	$0.4	$0.1	($0.0)	$0.3	$0.3	0	22
23	Lakeview - Greenfoe	Line	ATSI	$0.2	($0.4)	$0.1	$0.7	$0.0	$0.4	($0.1)	($0.4)	$0.3	344	132
36	Clover - Ross	Line	ATSI	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	270	0
45	Ottawa - West Freemont	Line	ATSI	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	38	14
60	Inland - Pofok Tie	Line	ATSI	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	88	2

Table G-35 ATSI Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($27.8)	($27.1)	($1.3)	($2.0)	($0.2)	$2.4	$1.8	($0.8)	($2.9)	8,240	2,026
2	Niles - Evergreen	Line	ATSI	$3.2	$0.8	$0.8	$3.2	($0.4)	$0.2	($0.6)	($1.2)	$1.9	892	54
3	Dickerson - Quince Orchard	Line	Pepco	($4.2)	($3.5)	$0.0	($0.7)	($0.2)	$0.4	($0.0)	($0.6)	($1.3)	284	152
4	West	Interface	500	($21.8)	($20.7)	($0.1)	($1.2)	($0.0)	$0.0	$0.0	($0.0)	($1.2)	1,758	40
5	Bayshore - Jeep	Line	ATSI	$0.8	($0.2)	$0.0	$1.0	$0.4	$0.2	$0.0	$0.2	$1.2	32	12
6	Clover	Transformer	Dominion	($2.8)	($2.3)	$0.4	($0.2)	$0.2	$0.4	($0.6)	($0.8)	($1.0)	2,476	938
7	Beaver - Sammis	Line	DLCO	($0.5)	($1.5)	($0.1)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	442	22
8	Burnham - Munster	Flowgate	MISO	$4.5	$3.7	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	2,304	0
9	South Canton - Torrey	Line	AEP	$1.4	$0.6	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	82	16
10	Danville - East Danville	Line	AEP	($3.8)	($3.3)	($0.2)	($0.8)	$0.1	$0.1	$0.1	$0.0	($0.8)	9,264	646
11	5004/5005 Interface	Interface	500	($5.0)	($5.1)	($0.1)	($0.0)	$0.2	$1.2	$0.2	($0.7)	($0.8)	1,810	940
12	Muskingum River - Waterford	Line	AEP	$0.8	$0.7	$0.1	$0.1	$0.1	($0.1)	($1.0)	($0.7)	($0.6)	1,066	106
13	AEP - DOM	Interface	500	($4.4)	($3.8)	($0.1)	($0.8)	$0.0	$0.1	$0.2	$0.2	($0.6)	3,578	370
14	Benton Harbor - Palisades	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.0)	($0.4)	($0.6)	($0.6)	134	264
15	Jeep - Dixie	Line	ATSI	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	28	0
20	Sammis - Wylie Ridge	Line	ATSI	($1.2)	($1.8)	($0.2)	$0.4	($0.0)	($0.0)	$0.0	$0.0	$0.4	484	8
29	Lakeview - Ottawa	Line	ATSI	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	($0.0)	$0.0	$0.3	46	4
31	Galion – GM Mansfield	Line	ATSI	$0.3	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	36	0
35	Galion - Leaside	Line	ATSI	$0.1	$0.1	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.1	$0.2	44	22
42	Brookside - Wellington	Line	ATSI	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	224	0

ComEd Control Zone

Table G-36 ComEd Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Woodstock	Flowgate	MISO	($3.9)	($29.3)	$7.5	$32.9	$0.0	$0.0	$0.0	$0.0	$32.9	2,146	0
2	Nelson - Cordova	Line	ComEd	$8.3	($9.4)	$7.3	$25.1	$0.4	$1.3	($6.5)	($7.4)	$17.7	5,286	576
3	Rantoul - Rantoul Jct	Flowgate	MISO	($39.7)	($52.1)	($1.0)	$11.4	$0.3	($0.2)	($0.8)	($0.3)	$11.1	4,072	630
4	Oak Grove - Galesburg	Flowgate	MISO	($13.0)	($26.0)	$7.8	$20.9	$0.3	$1.7	($9.1)	($10.5)	$10.4	7,244	2,718
5	Prairie State - W Mt. Vernon	Flowgate	MISO	($23.3)	($32.0)	$0.0	$8.8	$0.1	($0.1)	($0.0)	$0.2	$8.9	2,966	2,022
6	Belvidere - Woodstock	Line	ComEd	$0.3	($7.5)	($0.0)	$7.8	($0.7)	$4.1	($11.1)	($15.9)	$8.0	1,760	1,532
7	Pleasant Valley - Belvidere	Line	ComEd	($1.8)	($8.5)	$0.9	$7.6	$0.1	$0.1	($0.4)	($0.3)	$7.2	1,440	102
8	Dixon - Stillman Valley	Line	ComEd	$2.8	($3.5)	$0.9	$7.2	$0.2	$0.9	($0.6)	($1.3)	$6.0	3,896	212
9	Crete - St Johns Tap	Flowgate	MISO	($44.3)	($58.6)	($8.5)	$5.9	$0.6	$0.8	$0.1	($0.1)	$5.8	4,754	554
10	Beaver Channel - Albany	Flowgate	MISO	$8.4	($4.0)	$4.3	$16.7	($4.8)	($0.3)	($6.6)	($11.0)	$5.7	2,512	992
11	Hegewisch - Burnham	Line	ComEd	($9.9)	($15.0)	($1.0)	$4.2	($0.5)	$0.5	$2.0	$1.0	$5.2	2,252	576
12	AP South	Interface	500	($29.3)	($32.8)	($0.6)	$2.9	$1.9	$0.4	$0.8	$2.3	$5.1	5,172	702
13	Electric Jct - Nelson	Line	ComEd	($0.6)	($4.0)	$1.6	$5.0	$0.0	$0.0	($0.0)	($0.0)	$5.0	1,272	10
14	Silver Lake - Pleasant Valley	Line	ComEd	($2.6)	($6.0)	$0.9	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	2,238	0
15	East Frankfort - Braidwood	Line	ComEd	($0.7)	($4.5)	($0.2)	$3.7	($0.0)	$0.7	$0.9	$0.2	$3.9	632	98
17	Mazon - Mazon	Line	ComEd	$0.7	($1.6)	$1.5	$3.8	($0.1)	$0.1	($0.5)	($0.7)	$3.1	1,524	340
18	Belvidere - Chrysler Corp.	Line	ComEd	$0.3	($3.8)	($1.1)	$3.0	($0.0)	($0.0)	($0.0)	($0.0)	$3.0	726	2
19	Cherry Valley	Transformer	ComEd	$0.9	($2.2)	$0.0	$3.2	($0.0)	$0.4	($0.5)	($0.9)	$2.3	1,110	84
20	Lancaster - Maryland	Line	ComEd	$0.3	($0.2)	$0.2	$0.7	($0.3)	$0.7	($1.9)	($2.9)	$2.2	282	24
23	Nelson	Transformer	ComEd	($0.2)	($1.7)	$0.5	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	954	0

Table G-37 ComEd Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Electric Jct - Nelson	Line	ComEd	($5.1)	($43.6)	$6.2	$44.8	$1.2	$4.0	($5.1)	($7.9)	$36.9	5,886	316
2	Crete - St Johns Tap	Flowgate	MISO	($156.4)	($190.6)	($16.6)	$17.6	$7.0	$5.6	$7.6	$8.9	$26.5	6,756	2,240
3	AP South	Interface	500	($122.0)	($134.5)	($0.9)	$11.6	$7.6	$2.5	$0.3	$5.5	$17.1	8,240	2,026
4	East Frankfort - Crete	Line	ComEd	($56.3)	($71.2)	($5.0)	$10.0	$1.5	$0.5	$2.1	$3.1	$13.1	3,092	658
5	Bunsonville - Eugene	Flowgate	MISO	($39.8)	($51.0)	($0.1)	$11.1	$0.0	$0.0	($0.0)	($0.0)	$11.1	4,888	22
6	Pleasant Valley - Belvidere	Line	ComEd	($5.3)	($17.4)	$1.2	$13.3	($0.3)	$2.2	($1.3)	($3.8)	$9.5	2,214	630
7	5004/5005 Interface	Interface	500	($62.7)	($69.3)	($0.4)	$6.2	$4.0	$2.0	$0.5	$2.5	$8.7	1,810	940
8	Wylie Ridge	Transformer	AP	($38.5)	($43.2)	($0.1)	$4.6	$1.6	$0.4	($0.1)	$1.1	$5.7	3,836	760
9	Michigan City - Laporte	Flowgate	MISO	($40.7)	($43.4)	$1.7	$4.3	$2.5	$0.5	($1.0)	$1.0	$5.4	5,870	1,264
10	Lakeview - Pleasant Prairie	Flowgate	MISO	$0.3	$0.2	$0.2	$0.3	($0.3)	($0.0)	($4.8)	($5.1)	($4.8)	48	604
11	Brokaw - Gibson	Flowgate	MISO	($15.1)	($19.7)	$0.5	$5.2	$0.2	$0.1	($0.6)	($0.5)	$4.7	1,418	190
12	Waukegan - Zion	Line	ComEd	$0.7	($1.2)	$2.9	$4.8	$0.0	$0.0	($0.3)	($0.3)	$4.5	3,468	14
13	Pleasant Prairie - Zion	Flowgate	MISO	$0.1	($1.0)	$1.2	$2.3	$0.0	$0.1	($6.7)	($6.8)	($4.5)	672	420
14	Rantoul - Rantoul Jct	Flowgate	MISO	($14.3)	($18.3)	$0.0	$3.9	$0.3	$0.1	$0.1	$0.3	$4.2	1,106	376
15	Cherry Valley	Transformer	ComEd	$1.7	($1.8)	$0.5	$3.9	$0.1	$0.1	($0.2)	($0.2)	$3.7	1,406	164
17	Glidden - West Dekalb	Line	ComEd	($0.7)	($3.9)	$0.3	$3.5	$0.0	($0.0)	($0.0)	($0.0)	$3.5	2,238	2
20	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$1.2	($0.1)	$1.7	$3.0	$3.0	0	454
22	Wilton Center	Transformer	ComEd	($1.6)	($1.9)	$2.5	$2.8	$0.1	$0.1	$0.0	$0.0	$2.9	134	52
24	Belvidere - Woodstock	Line	ComEd	($0.1)	($3.0)	$0.3	$3.3	$0.0	$0.2	($0.2)	($0.5)	$2.8	378	86
26	Woodstock - 12205	Line	ComEd	($0.7)	($3.1)	$0.2	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	790	0

DAY Control Zone

Table G-38 DAY Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Stuart - Killen	Line	DAY	$0.1	$0.1	$0.8	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	714	0
2	Foster2 - Pierce	Line	DAY	$0.7	$0.5	$0.7	$0.9	($0.0)	$0.0	($0.1)	($0.1)	$0.8	2,964	22
3	Rantoul - Rantoul Jct	Flowgate	MISO	$0.9	$0.9	$0.6	$0.6	$0.0	($0.0)	($0.1)	($0.1)	$0.6	4,072	630
4	Kyger Creek - DOE	Line	EXT	($0.0)	($0.0)	$0.5	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,076	0
5	AP South	Interface	500	($4.4)	($4.2)	($0.1)	($0.3)	$0.1	$0.3	$0.1	($0.1)	($0.4)	5,172	702
6	Belvidere - Woodstock	Line	ComEd	($0.0)	($0.0)	$0.0	$0.0	$0.0	($0.0)	($0.4)	($0.4)	($0.3)	1,760	1,532
7	Rantoul Jct - Sidney	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.3)	($0.3)	($0.3)	0	662
8	Crete - St Johns Tap	Flowgate	MISO	$0.8	$0.7	$0.3	$0.4	$0.0	($0.0)	($0.2)	($0.1)	$0.3	4,754	554
9	Nelson - Cordova	Line	ComEd	($0.4)	($0.5)	$0.4	$0.5	($0.0)	$0.0	($0.3)	($0.3)	$0.2	5,286	576
10	West	Interface	500	($3.0)	($2.9)	($0.0)	($0.2)	$0.1	$0.2	$0.0	($0.1)	($0.2)	1,682	260
11	Woodstock	Flowgate	MISO	($0.0)	($0.0)	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	2,146	0
12	Breed - Wheatland	Flowgate	MISO	$0.8	$0.8	$0.3	$0.3	$0.0	($0.0)	($0.1)	($0.0)	$0.2	5,642	856
13	Toddhunt - Trenton	Line	DEOK	($0.0)	($0.5)	($0.2)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,286	0
14	Rising	Flowgate	MISO	$0.2	$0.3	$0.1	$0.1	$0.0	($0.0)	($0.3)	($0.3)	($0.2)	816	726
15	Palisades - Roosevelt	Flowgate	MISO	($0.3)	($0.4)	$0.1	$0.2	($0.0)	$0.0	($0.1)	($0.1)	$0.2	1,710	418
22	Stuart - Clinton	Line	DAY	$0.1	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	80	0
57	Trenton - Hutchings	Line	DAY	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	96	0
61	Stuart - Atlanta	Line	DAY	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	104	0
64	Hillcrest - Stuart	Line	DAY	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	114	0
100	Darby - Watkins Tap	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	136	0

Table G-39 DAY Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pierce - Foster	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.2)	($1.7)	($1.6)	($1.6)	0	40
2	West	Interface	500	($7.3)	($8.7)	($0.0)	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	1,758	40
3	AP South	Interface	500	($16.1)	($17.7)	($0.4)	$1.2	$0.8	$1.5	$0.5	($0.2)	$1.0	8,240	2,026
4	AEP - DOM	Interface	500	($3.7)	($4.7)	($0.0)	$0.9	$0.1	$0.2	$0.1	$0.0	$0.9	3,578	370
5	Danville - East Danville	Line	AEP	($2.5)	($3.4)	($0.1)	$0.8	$0.1	$0.2	$0.0	($0.1)	$0.8	9,264	646
6	Burnham - Munster	Flowgate	MISO	$1.1	$1.7	$0.1	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	2,304	0
7	Clover	Transformer	Dominion	($1.9)	($2.4)	$0.1	$0.6	$0.2	$0.2	($0.1)	($0.1)	$0.5	2,476	938
8	Crete - St Johns Tap	Flowgate	MISO	$2.8	$3.1	($0.1)	($0.4)	($0.1)	($0.1)	($0.2)	($0.1)	($0.5)	6,756	2,240
9	East Frankfort - Crete	Line	ComEd	$1.0	$1.4	$0.1	($0.3)	($0.0)	$0.0	($0.1)	($0.1)	($0.5)	3,092	658
10	Breed - Wheatland	Line	AEP	$0.5	$0.9	($0.0)	($0.4)	($0.0)	($0.0)	($0.0)	($0.0)	($0.4)	2,484	2
11	Wolfcreek	Transformer	AEP	($1.7)	($2.1)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	5,122	452
12	Bunsonville - Eugene	Flowgate	MISO	$1.7	$2.2	$0.1	($0.4)	$0.0	($0.0)	($0.0)	$0.0	($0.4)	4,888	22
13	Valley	Transformer	Dominion	($0.9)	($1.3)	($0.0)	$0.4	$0.1	$0.2	$0.0	($0.0)	$0.3	438	196
14	Belmont	Transformer	AP	($1.5)	($1.8)	$0.1	$0.4	$0.0	$0.1	($0.0)	($0.1)	$0.3	8,750	998
15	Brokaw - Gibson	Flowgate	MISO	$0.4	$0.8	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	($0.0)	($0.3)	1,418	190

DEOK Control Zone

Table G-40 DEOK Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Miami Fort - Hebron	Flowgate	MISO	$2.9	$0.5	$0.2	$2.6	($0.2)	($0.0)	($0.1)	($0.2)	$2.4	2,106	152
2	Beckjord - Pierce	Line	DEOK	$1.9	$0.6	$0.4	$1.8	$0.2	($0.0)	($0.4)	($0.2)	$1.6	700	96
3	Graceton - Raphael Road	Line	BGE	$2.1	$1.2	($0.0)	$0.9	$0.0	($0.1)	$0.0	$0.1	$1.0	5,328	1,446
4	Clover	Transformer	Dominion	($2.8)	($2.1)	$0.0	($0.7)	$0.0	$0.1	($0.0)	($0.2)	($0.8)	3,128	904
5	Bedington - Black Oak	Interface	500	($2.0)	($1.5)	($0.0)	($0.6)	$0.0	$0.2	$0.0	($0.2)	($0.8)	1,560	108
6	West	Interface	500	($4.0)	($3.3)	($0.0)	($0.8)	$0.1	$0.0	$0.0	$0.1	($0.7)	1,682	260
7	Toddhunt - Trenton	Line	DEOK	$0.2	($0.5)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,286	0
8	AEP - DOM	Interface	500	($1.9)	($1.5)	$0.0	($0.3)	($0.1)	$0.1	($0.1)	($0.2)	($0.6)	4,190	122
9	AP South	Interface	500	($5.6)	($4.8)	($0.1)	($0.8)	$0.2	($0.0)	$0.1	$0.3	($0.5)	5,172	702
10	Miami Fort	Transformer	DEOK	$0.6	$0.2	$0.2	$0.5	$0.0	($0.0)	($0.1)	($0.1)	$0.5	2,544	104
11	Foster2 - Pierce	Line	DAY	$0.5	$0.4	$0.4	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	2,964	22
12	Rantoul - Rantoul Jct	Flowgate	MISO	$1.3	$0.9	$0.2	$0.5	($0.0)	($0.0)	($0.1)	($0.1)	$0.4	4,072	630
13	Hebron - Constance	Line	DEOK	$0.4	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	550	0
14	Loudoun - Gainsville	Line	Dominion	($0.9)	($0.6)	($0.0)	($0.3)	$0.0	$0.0	$0.0	($0.0)	($0.3)	322	38
15	Crete - St Johns Tap	Flowgate	MISO	$1.1	$0.9	$0.1	$0.3	$0.0	($0.0)	($0.1)	($0.0)	$0.3	4,754	554
19	Silver Grove	Other	DEOK	$0.1	($0.1)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	354	0
22	Miami Fort - Miami Fort	Line	DEOK	$0.1	$0.1	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	154	0
27	Miami Fort- Terminal	Line	DEOK	($0.0)	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	324	0
37	Todd Hunter - Trenton	Line	DEOK	$0.1	($0.0)	$0.0	$0.1	($0.1)	$0.1	($0.1)	($0.2)	($0.1)	110	0
47	Rochelle - Terminal	Line	DEOK	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	16	0

DLCO Control Zone

Table G-41 DLCO Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$3.9	($0.2)	$0.2	$4.2	$0.1	$0.0	($0.1)	($0.0)	$4.2	590	60
2	Brunot Island - Montour	Line	DLCO	$1.2	($0.4)	$0.1	$1.8	($0.0)	$0.4	($0.2)	($0.6)	$1.2	772	418
3	AP South	Interface	500	($5.8)	($6.5)	($0.2)	$0.6	$0.0	$0.0	$0.2	$0.2	$0.8	5,172	702
4	Crescent - Montour	Line	DLCO	$0.4	($0.3)	($0.0)	$0.6	($0.0)	$0.1	($0.1)	($0.2)	$0.5	202	46
5	Beaver - Clinton	Line	DLCO	$0.2	($0.3)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	228	0
6	Collier	Transformer	DLCO	$0.4	$0.0	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	82	38
7	Clinton - Findlay	Line	DLCO	$0.3	$0.0	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	146	0
8	Arsenal - Brunot Island	Line	DLCO	$0.4	$0.2	$0.1	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	230	6
9	St. Joe	Other	DLCO	$0.2	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,426	0
10	Carson - Homested	Line	DLCO	$0.2	($0.0)	$0.0	$0.2	$0.0	($0.0)	($0.0)	($0.0)	$0.2	42	2
11	Elrama - Dravosburg	Line	DLCO	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	($0.0)	$0.2	$0.2	0	20
12	Crescent - Mansfield	Line	DLCO	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	20	16
13	Bedington - Black Oak	Interface	500	($2.0)	($1.8)	($0.1)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	1,560	108
14	West	Interface	500	($3.2)	($3.4)	($0.1)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.2	1,682	260
15	Tiltonsville - Windsor	Line	AP	$0.3	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	1,464	14
20	Crescent - Sewickly	Line	DLCO	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	20	0
23	Carson - Oakland	Line	DLCO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	28	4
34	Neville Tap - Sewickley	Line	DLCO	$0.0	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	18	0
74	Beaver - Sammis	Line	DLCO	($0.0)	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	98	0
78	Brunot Island - Neville	Line	DLCO	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0

Table G-42 DLCO Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$5.9	($0.4)	$0.1	$6.4	($0.1)	$0.1	($0.2)	($0.4)	$6.0	714	206
2	Wylie Ridge	Transformer	AP	($11.5)	($16.8)	($0.4)	$4.8	($0.4)	($0.1)	$0.2	($0.2)	$4.7	3,836	760
3	AP South	Interface	500	($18.6)	($23.3)	($0.5)	$4.1	($1.3)	$0.0	$0.4	($0.9)	$3.3	8,240	2,026
4	Collier - Elwyn	Line	DLCO	$1.8	($0.2)	$0.0	$2.0	$0.1	$0.1	($0.0)	($0.0)	$1.9	504	60
5	Brunot Island - Forbes	Line	DLCO	$0.7	($0.1)	$0.0	$0.8	($0.0)	($0.1)	($0.0)	$0.0	$0.8	172	72
6	Yukon	Transformer	AP	$2.0	$1.5	$0.1	$0.5	$0.3	($0.2)	($0.2)	$0.3	$0.8	750	180
7	AEP - DOM	Interface	500	($1.8)	($2.6)	$0.0	$0.8	($0.1)	($0.0)	$0.0	($0.0)	$0.7	3,578	370
8	Crete - St Johns Tap	Flowgate	MISO	$2.2	$2.9	$0.1	($0.7)	$0.1	$0.0	($0.0)	$0.1	($0.6)	6,756	2,240
9	5004/5005 Interface	Interface	500	($7.7)	($9.4)	($0.1)	$1.6	($0.6)	$0.5	$0.1	($1.0)	$0.6	1,810	940
10	Bedington - Black Oak	Interface	500	($2.2)	($2.7)	($0.0)	$0.6	($0.0)	$0.0	$0.0	($0.0)	$0.6	1,358	14
11	Beaver - Sammis	Line	DLCO	($0.6)	($1.4)	($0.0)	$0.7	($0.1)	$0.1	$0.0	($0.2)	$0.5	442	22
12	Arsenal - Highland	Line	DLCO	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.3)	$0.0	$0.4	$0.5	168	30
13	West	Interface	500	($6.8)	($7.2)	($0.1)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.4	1,758	40
14	Burnham - Munster	Flowgate	MISO	$0.9	$1.2	$0.0	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	2,304	0
15	East Frankfort - Crete	Line	ComEd	$0.8	$1.2	$0.0	($0.3)	$0.0	$0.0	($0.0)	$0.0	($0.3)	3,092	658
18	Arsenal - Brunot Island	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	100	18
20	Clinton - Findlay	Line	DLCO	$0.2	($0.0)	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.2	48	24
23	St. Joe	Other	DLCO	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	878	0
24	Beaver - Clinton	Line	DLCO	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	68	0
33	Arsenal	Transformer	DLCO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	34	0

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table G-43 Dominion Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$100.2	$82.3	$2.0	$20.0	$0.6	($1.5)	($2.9)	($0.8)	$19.2	5,172	702
2	Clover	Transformer	Dominion	$25.5	$15.2	$5.4	$15.7	($0.7)	$0.3	($7.3)	($8.3)	$7.4	3,128	904
3	Graceton - Raphael Road	Line	BGE	$53.4	$48.2	$1.3	$6.6	($0.1)	($0.9)	($1.1)	($0.2)	$6.4	5,328	1,446
4	Loudoun - Gainsville	Line	Dominion	($9.5)	($16.4)	($0.7)	$6.3	$0.5	$0.8	$0.2	($0.1)	$6.2	322	38
5	Bedington - Black Oak	Interface	500	$20.6	$17.2	$0.9	$4.3	$0.1	($0.1)	($0.5)	($0.3)	$4.1	1,560	108
6	Northwest	Other	BGE	$12.9	$10.9	$0.3	$2.3	($0.1)	($0.8)	($0.6)	$0.1	$2.4	1,168	804
7	Fredericksburg - Cranes Corner	Line	Dominion	($4.2)	($6.4)	($0.1)	$2.0	$0.4	$0.6	$0.1	($0.1)	$1.9	422	60
8	AEP - DOM	Interface	500	$20.6	$20.3	$0.6	$0.9	$0.1	($0.3)	$0.1	$0.5	$1.4	4,190	122
9	Halifax - Person	Line	Dominion	$0.0	$0.0	$0.0	$0.0	$0.1	($0.4)	($1.8)	($1.4)	($1.4)	0	120
10	Crete - St Johns Tap	Flowgate	MISO	$7.4	$6.5	$0.2	$1.1	($0.0)	($0.1)	($0.0)	$0.0	$1.1	4,754	554
11	Elmont	Transformer	Dominion	$2.4	$1.5	$0.0	$1.0	$0.1	($0.1)	($0.2)	$0.0	$1.0	142	96
12	Rantoul - Rantoul Jct	Flowgate	MISO	$7.6	$6.9	$0.4	$1.0	($0.0)	($0.1)	($0.1)	($0.0)	$1.0	4,072	630
13	Valley	Transformer	Dominion	$2.4	$1.7	$0.1	$0.9	($0.2)	($0.3)	($0.1)	($0.0)	$0.9	214	22
14	Doubs - Mount Storm	Line	500	$1.3	$0.5	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	160	0
15	Beechwood - Kerr Dam	Line	Dominion	$1.6	$0.5	$0.0	$1.1	($0.1)	$0.1	($0.0)	($0.3)	$0.8	1,124	236
24	Hollymead - Charlottesville	Line	Dominion	$1.3	$0.8	$0.1	$0.7	($0.1)	($0.4)	($0.5)	($0.2)	$0.4	396	88
27	Mount Storm	Other	Dominion	$1.3	$0.9	$0.0	$0.4	$0.0	($0.0)	($0.1)	($0.0)	$0.4	106	34
29	Skimmer - Balcony Falls	Line	Dominion	$0.2	$0.1	$0.0	$0.0	($0.1)	($0.0)	($0.3)	($0.4)	($0.4)	38	66
31	Battleboro	Line	Dominion	$0.9	$0.7	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	302	18
35	Rocky Mount - Battleboro	Line	Dominion	$0.9	$0.6	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	210	0

Table G-44 Dominion Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$313.4	$233.9	$3.4	$82.9	($0.3)	$0.6	($4.1)	($5.0)	$77.9	8,240	2,026
2	Clover	Transformer	Dominion	$23.2	$7.9	$4.4	$19.8	($0.5)	$2.7	($8.2)	($11.4)	$8.4	2,476	938
3	AEP - DOM	Interface	500	$51.0	$46.9	$1.4	$5.6	($0.3)	($0.6)	($0.4)	($0.1)	$5.5	3,578	370
4	Danville - East Danville	Line	AEP	$60.1	$55.4	$0.7	$5.4	($0.8)	($1.5)	($0.6)	$0.0	$5.4	9,264	646
5	Bedington - Black Oak	Interface	500	$32.0	$28.6	$0.6	$4.0	$0.0	($0.0)	($0.1)	$0.0	$4.0	1,358	14
6	Valley	Transformer	Dominion	$24.7	$20.0	$1.1	$5.8	($1.3)	($0.1)	($1.3)	($2.5)	$3.3	438	196
7	Chaparral - Carson	Line	Dominion	$5.1	$4.4	$0.5	$1.2	$0.2	$1.6	($3.0)	($4.5)	($3.3)	392	360
8	Dickerson - Quince Orchard	Line	Pepco	($32.1)	($29.0)	($0.9)	($4.1)	$0.4	$1.1	$1.5	$0.8	($3.3)	284	152
9	Graceton - Raphael Road	Line	BGE	$19.1	$16.5	$0.5	$3.1	($0.2)	($0.6)	($0.6)	($0.2)	$2.9	2,324	830
10	Crete - St Johns Tap	Flowgate	MISO	$25.7	$22.9	$0.1	$2.9	($0.3)	($0.4)	($0.2)	($0.0)	$2.9	6,756	2,240
11	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	($1.0)	($1.6)	($3.4)	($2.9)	($2.9)	0	218
12	Cloverdale - Lexington	Line	500	$12.0	$8.7	$0.9	$4.2	($0.3)	($0.6)	($2.1)	($1.7)	$2.5	1,204	854
13	Fredericksburg - Cranes Corner	Line	Dominion	($3.3)	($6.0)	($0.2)	$2.5	$0.2	$0.4	$0.2	($0.0)	$2.5	250	46
14	Wylie Ridge	Transformer	AP	$19.6	$17.6	$0.8	$2.8	$0.1	($0.1)	($0.6)	($0.3)	$2.5	3,836	760
15	Hopewell - Chesterfield	Line	Dominion	$7.8	$4.6	$0.3	$3.5	($0.3)	($1.2)	($2.0)	($1.2)	$2.3	308	126
17	Halifax - Mount Laurel	Line	Dominion	$4.7	$1.8	$0.2	$3.1	($0.4)	$0.3	($0.2)	($0.9)	$2.3	1,456	294
19	Dooms	Transformer	Dominion	$18.2	$13.6	$1.1	$5.7	($5.0)	($1.1)	($3.7)	($7.6)	($1.9)	298	236
22	Bristers - Ox	Line	Dominion	($1.7)	($3.1)	$0.0	$1.5	$0.4	$0.5	($0.1)	($0.1)	$1.4	66	50
23	Powhatan - Bremo	Line	Dominion	$2.4	$1.3	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	60	0
28	Crozet - Dooms	Line	Dominion	$3.2	$2.6	$0.2	$0.8	($0.0)	($0.0)	($0.0)	($0.0)	$0.8	236	4

Marginal Losses

Zonal Marginal Loss Costs

Table G-45 provides marginal loss costs by control zone and type for the 2012. Table G-46 provides total marginal loss costs by control zone and month for the 2011 and 2012.

Table G-45 Marginal loss costs by control zone and type (Dollars (Millions)): 2012[4]

	Marginal Loss Costs by Control Zone (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$18.6	$3.6	$0.6	$15.6	($0.0)	($0.1)	($0.5)	($0.4)	$0.0	$15.2
AEP	($154.8)	($367.7)	$0.8	$213.7	$7.0	$5.8	($9.0)	($7.8)	$0.0	$205.9
AP	($3.9)	($77.3)	$7.5	$80.9	$1.6	$6.4	($7.3)	($12.1)	$0.0	$68.7
ATSI	($3.3)	($71.9)	$2.8	$71.4	$9.0	$2.0	($3.3)	$3.7	$0.0	$75.1
BGE	$88.5	$47.1	$8.9	$50.3	$1.7	($0.6)	($7.6)	($5.3)	$0.0	$45.0
ComEd	($303.7)	($483.2)	($2.2)	$177.2	$8.1	$2.0	$1.6	$7.7	$0.0	$184.9
DAY	($4.6)	($45.7)	($1.7)	$39.4	($1.4)	$2.1	($1.1)	($4.6)	$0.0	$34.8
DEOK	($48.2)	($54.4)	($3.7)	$2.5	$2.4	$1.4	($0.3)	$0.7	$0.0	$3.2
DLCO	($17.2)	($29.2)	$0.4	$12.4	($0.4)	$0.0	($0.4)	($0.9)	$0.0	$11.5
Dominion	$80.2	($6.8)	$8.7	$95.7	$4.9	$3.7	($6.8)	($5.6)	$0.0	$90.1
DPL	$48.5	$11.0	$4.9	$42.4	($2.3)	$0.3	($3.9)	($6.5)	$0.0	$35.9
External	($26.6)	($40.1)	($61.3)	($47.8)	($2.6)	($5.1)	$23.3	$25.8	$0.0	($22.0)
JCPL	$35.8	$12.9	($0.2)	$22.8	$0.3	$0.4	($1.0)	($1.1)	$0.0	$21.7
Met-Ed	$11.5	($2.3)	$0.1	$13.9	$0.4	$0.1	$0.2	$0.5	$0.0	$14.4
PECO	$55.8	$26.2	$0.6	$30.2	$0.0	$0.0	($0.5)	($0.5)	$0.0	$29.6
PENELEC	($1.1)	($45.9)	$2.2	$47.0	$1.6	$0.1	($2.5)	($1.0)	$0.0	$46.0
Pepco	$75.8	$39.0	$6.6	$43.4	($1.1)	($0.2)	($5.5)	($6.4)	$0.0	$37.0
PPL	$23.5	($10.7)	($3.4)	$30.8	$1.9	$0.9	$1.9	$2.9	$0.0	$33.7
PSEG	$80.0	$35.0	$15.0	$60.0	$1.0	$4.3	($7.9)	($11.3)	$0.0	$48.7
RECO	$2.1	$0.0	$0.1	$2.2	$0.0	($0.0)	($0.1)	($0.1)	$0.0	$2.1
Total	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7

4 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 external interfaces.

Table G-46 Monthly marginal loss costs by control zone (Dollars (Millions)): 2011 and 2012

Marginal Loss Costs by Control Zone (Millions)														
2011														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	$2.9	$2.0	$1.8	$1.5	$1.5	$3.2	$6.0	$3.2	$1.9	$0.8	$0.8	$0.3	$0.0	$26.0
AEP	$42.3	$25.8	$24.0	$19.4	$18.3	$30.6	$54.9	$34.5	$24.6	$15.4	$15.9	$12.9	$0.0	$318.6
AP	$14.3	$8.4	$7.7	$6.5	$6.6	$9.1	$16.1	$10.1	$7.4	$5.3	$5.3	$5.3	$0.0	$102.0
ATSI	NA	NA	NA	NA	NA	$1.5	$2.7	$2.2	$1.7	$5.2	$2.8	$3.2	$0.0	$19.3
BGE	$6.5	$5.0	$3.9	$3.2	$3.8	$6.3	$11.7	$6.6	$4.8	$3.3	$3.5	$2.9	$0.0	$61.3
ComEd	$32.3	$21.9	$23.1	$17.8	$15.3	$22.7	$30.1	$21.0	$21.1	$18.0	$18.6	$17.3	$0.0	$259.2
DAY	$5.2	$5.0	$4.5	$2.8	$4.1	$5.9	$10.3	$7.0	$6.7	$5.6	$4.8	$4.2	$0.0	$66.1
DEOK	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	$0.0	$0.0
DLCO	$2.2	$1.6	$0.7	$0.8	$1.2	$1.2	$1.3	$1.1	$1.2	$1.3	$1.1	$0.9	$0.0	$14.6
Dominion	$19.8	$11.6	$9.7	$4.3	$8.2	$8.3	$24.0	$14.6	$10.2	$6.5	$6.0	$5.5	$0.0	$128.7
DPL	$7.7	$5.3	$3.6	$2.7	$2.6	$4.7	$7.9	$5.5	$3.8	$1.9	$1.7	$1.0	$0.0	$48.5
EXT	$6.4	$4.1	$0.0	($0.7)	($0.1)	($2.5)	($6.9)	($7.2)	($7.4)	($3.6)	($6.5)	($2.6)	$0.0	($26.9)
JCPL	$6.2	$4.1	$3.1	$2.5	$2.3	$3.6	$6.6	$3.3	$2.7	$1.4	$0.7	$1.3	$0.0	$37.9
Met-Ed	$2.1	$1.4	$1.4	$1.2	$1.5	$1.6	$2.4	$1.8	$1.4	$1.4	$1.5	$1.6	$0.0	$19.1
PECO	$6.6	$3.5	$3.5	$3.7	$4.9	$6.3	$10.0	$5.7	$3.7	$3.8	$3.7	$3.9	$0.0	$59.2
PENELEC	$8.9	$5.3	$3.6	$3.1	$5.0	$6.9	$10.3	$7.2	$4.7	$3.4	$3.2	$1.9	$0.0	$63.5
Pepco	$5.9	$3.7	$3.9	$3.1	$3.7	$5.1	$8.2	$5.2	$4.1	$2.8	$2.5	$2.3	$0.0	$50.5
PPL	$8.6	$4.7	$3.0	$2.6	$3.1	$4.4	$7.9	$6.1	$3.9	$4.2	$4.4	$4.0	$0.0	$56.9
PSEG	$7.3	$6.1	$6.3	$4.6	$5.2	$6.4	$9.7	$6.2	$6.0	$5.5	$4.0	$4.5	$0.0	$71.8
RECO	$0.5	$0.3	$0.3	$0.2	$0.2	$0.3	$0.5	$0.3	$0.3	$0.2	$0.1	$0.1	$0.0	$3.2
Total	$185.7	$119.9	$104.0	$79.2	$87.3	$125.4	$213.7	$134.5	$102.9	$82.0	$74.3	$70.6	$0.0	$1,379.6

Marginal Loss Costs by Control Zone (Millions)														
2012														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	$0.9	$0.7	$0.7	$0.4	$0.7	$1.4	$3.1	$2.5	$1.2	$1.0	$1.5	$1.2	$0.0	$15.2
AEP	$22.0	$17.4	$11.8	$13.2	$14.1	$19.2	$31.7	$21.7	$13.9	$14.9	$14.7	$11.5	$0.0	$205.9
AP	$5.4	$5.4	$4.0	$3.2	$3.9	$6.7	$8.3	$6.7	$5.9	$5.0	$7.7	$6.6	$0.0	$68.7
ATSI	$5.8	$5.9	$5.1	$4.4	$6.8	$7.4	$11.5	$6.5	$4.6	$5.1	$5.4	$6.7	$0.0	$75.1
BGE	$4.2	$4.1	$3.2	$2.4	$2.4	$4.3	$6.3	$4.5	$3.2	$2.9	$4.1	$3.5	$0.0	$45.0
ComEd	$17.9	$13.8	$11.5	$11.2	$12.4	$15.6	$21.4	$16.0	$13.9	$14.7	$19.5	$16.9	$0.0	$184.9
DAY	$3.4	$2.4	$2.6	$1.7	$2.8	$3.7	$5.1	$2.4	$3.4	$2.4	$1.7	$3.3	$0.0	$34.8
DEOK	$0.0	$0.6	($0.9)	($0.3)	$0.5	$0.0	$0.8	$2.0	($0.4)	$0.6	$0.2	$0.1	$0.0	$3.2
DLCO	$1.0	$1.2	$1.1	$0.4	$0.8	$1.1	$1.2	$1.0	$0.7	$0.3	$1.3	$1.4	$0.0	$11.5
Dominion	$8.0	$6.7	$5.7	$4.7	$6.0	$9.2	$14.8	$9.6	$7.0	$5.7	$7.4	$5.3	$0.0	$90.1
DPL	$3.5	$2.9	$2.1	$1.6	$1.9	$3.2	$6.2	$4.2	$2.5	$1.9	$3.2	$2.7	$0.0	$35.9
EXT	($0.5)	($1.6)	($0.4)	($3.6)	($1.6)	($0.9)	($2.3)	($0.3)	($2.1)	($5.1)	($2.5)	($1.1)	$0.0	($22.0)
JCPL	$1.9	$1.4	$1.1	$1.0	$1.2	$2.2	$3.6	$2.3	$1.2	$1.4	$2.1	$2.4	$0.0	$21.7
Met-Ed	$1.3	$1.2	$1.0	$0.9	$0.8	$1.3	$2.2	$1.2	$1.1	$1.1	$1.1	$1.2	$0.0	$14.4
PECO	$3.5	$2.7	$2.2	$1.7	$2.9	$3.2	$6.2	$2.4	$2.1	$1.8	$0.5	$0.7	$0.0	$29.6
PENELEC	$4.8	$2.6	$3.3	$1.7	$4.1	$4.6	$7.6	$4.2	$3.1	$2.5	$3.7	$3.8	$0.0	$46.0
Pepco	$4.0	$4.1	$2.9	$2.0	$2.0	$3.2	$4.2	$3.4	$2.9	$2.8	$2.8	$2.7	$0.0	$37.0
PPL	$3.8	$2.4	$2.3	$1.7	$2.1	$2.4	$5.4	$3.7	$3.2	$2.5	$2.9	$1.3	$0.0	$33.7
PSEG	$4.1	$3.3	$2.6	$2.5	$3.4	$4.4	$6.0	$4.2	$3.3	$3.0	$5.1	$6.9	$0.0	$48.7
RECO	$0.2	$0.1	$0.1	$0.1	$0.1	$0.2	$0.3	$0.3	$0.1	$0.1	$0.2	$0.2	$0.0	$2.1
Total	$95.2	$77.2	$61.9	$51.0	$67.1	$92.5	$143.4	$98.5	$70.8	$64.1	$82.5	$77.5	$0.0	$981.7

Energy

Zonal Energy Costs

Table G-47 provides energy costs by control zone and type for the 2012. Table G-48 provides total energy costs by control zone and month for the 2011 and 2012.

Table G-47 Energy costs by control zone and type (Dollars (Millions)): 2012

Energy Costs by Control Zone (Millions)										
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$400.6	$114.3	$0.0	$286.2	$2.2	($2.7)	$0.0	$4.9	$0.1	$291.3
AEP	$5,281.2	$5,870.0	$0.0	($588.8)	($109.6)	($70.1)	$0.0	($39.5)	$1.6	($626.7)
AP	$1,752.4	$2,080.3	$0.0	($327.8)	($5.4)	($168.5)	$0.0	$163.1	$0.5	($164.1)
ATSI	$2,546.8	$2,301.4	$0.0	$245.4	($16.2)	($84.0)	$0.0	$67.8	$0.8	$314.0
BGE	$1,927.2	$1,576.3	$0.0	$350.9	$37.0	($17.4)	$0.0	$54.4	$0.4	$405.7
ComEd	$5,126.8	$5,816.2	$0.0	($689.3)	($85.6)	($53.6)	$0.0	($32.0)	$1.2	($720.2)
DAY	$671.5	$655.9	$0.0	$15.6	$11.5	($28.4)	$0.0	$39.9	$0.2	$55.7
DEOK	$932.9	$723.2	$0.0	$209.7	$0.8	($26.9)	$0.0	$27.7	$0.3	$237.7
DLCO	$548.3	$622.0	$0.0	($73.8)	$13.2	($3.2)	$0.0	$16.4	$1.1	($56.3)
Dominion	$6,302.1	$6,036.5	$0.0	$265.6	($53.0)	($214.4)	$0.0	$161.4	$0.2	$427.2
DPL	$705.9	$321.8	$0.0	$384.1	$9.5	$67.1	$0.0	($57.6)	$0.2	$326.7
External	$591.9	$766.6	$0.0	($174.7)	$141.6	$267.1	$0.0	($125.5)	$0.0	($300.2)
JCPL	$858.2	$492.3	$0.0	$365.9	($8.4)	$5.3	$0.0	($13.8)	$0.3	$352.5
Met-Ed	$659.8	$849.2	$0.0	($189.4)	($4.9)	($7.8)	$0.0	$2.9	$0.2	($186.3)
PECO	$1,879.2	$2,549.4	$0.0	($670.2)	($13.1)	$14.6	$0.0	($27.7)	$0.5	($697.3)
PENELEC	$1,778.8	$2,254.7	$0.0	($475.9)	($78.5)	$20.1	$0.0	($98.6)	$0.2	($574.3)
Pepco	$2,106.8	$1,456.8	$0.0	$650.0	($55.1)	$0.5	$0.0	($55.6)	$0.4	$594.8
PPL	$1,774.7	$2,088.5	$0.0	($313.9)	$33.5	$14.5	$0.0	$19.0	$0.5	($294.4)
PSEG	$1,741.1	$1,674.7	$0.0	$66.3	$11.2	$110.3	$0.0	($99.1)	$0.5	($32.3)
RECO	$55.1	$1.1	$0.0	$54.0	($0.6)	($0.4)	$0.0	($0.2)	$0.0	$53.8
Total	$37,641.2	$38,251.1	$0.0	($609.9)	($169.8)	($177.6)	$0.0	$7.8	$9.1	($593.0)

Table G-48 Monthly energy costs by control zone (Dollars (Millions)): 2011 and 2012

Energy Costs by Control Zone (Millions)														
2011														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$37.4	$27.3	$28.1	$25.4	$28.3	$39.9	$61.3	$39.1	$30.1	$24.5	$22.4	$25.4	$0.4	$389.4
AEP	($86.5)	($56.4)	($67.0)	($71.3)	($29.3)	($130.4)	($199.5)	($126.9)	($74.5)	($22.6)	$1.0	($27.6)	$5.2	($885.8)
AP	$6.8	$7.8	$11.2	($10.8)	($5.4)	($37.4)	($38.2)	($29.7)	($20.6)	($11.6)	($14.2)	($13.9)	$1.8	($154.0)
ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$49.9	$37.5	$16.1	$12.8	$44.6	$29.8	$32.6	$1.6	$224.8
BGE	$42.8	$52.6	$35.4	$21.6	$26.0	$49.9	$80.2	$47.2	$33.9	$28.5	$26.8	$29.3	$1.3	$475.5
ComEd	($123.9)	($87.6)	($96.8)	($78.9)	($52.4)	($89.3)	($36.7)	($51.3)	($94.6)	($94.6)	($95.8)	($99.0)	$3.9	($997.2)
DAY	$0.3	($14.8)	($9.9)	$0.7	($12.5)	($11.3)	($20.3)	($12.9)	($30.7)	($33.7)	($24.8)	($24.0)	$0.7	($193.2)
DEOK	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
DLCO	($13.9)	($14.2)	$10.9	($6.2)	($17.8)	($12.3)	($0.8)	($3.2)	($13.4)	($11.6)	($13.8)	($4.5)	$3.7	($97.1)
Dominion	$80.2	$49.6	$36.0	$53.0	$66.3	$73.7	$46.4	$55.7	$65.5	$82.3	$73.8	$38.3	$0.7	$721.6
DPL	$82.2	$51.3	$40.5	$28.3	$34.7	$45.6	$62.8	$45.9	$37.0	$29.6	$25.9	$33.3	$0.6	$517.7
External	($38.7)	($2.2)	$16.3	$25.3	($0.3)	($10.0)	($47.8)	$35.4	$52.8	$16.5	$13.7	$33.1	$0.0	$94.1
JCPL	$72.7	$44.5	$37.4	$26.1	$36.6	$55.0	$89.9	$52.6	$34.4	$18.6	$17.5	$28.2	$0.9	$514.5
Met-Ed	($23.1)	($16.6)	($16.6)	($30.3)	($20.2)	($27.9)	($37.5)	($28.0)	($20.5)	($16.9)	($4.3)	($16.5)	$0.6	($257.8)
PECO	($51.3)	($55.0)	($71.3)	($45.1)	($93.1)	($65.5)	($64.9)	($65.2)	($47.1)	($51.8)	($66.9)	($62.8)	$1.6	($738.3)
PENELEC	($110.0)	($67.2)	($39.7)	($44.9)	($70.4)	($104.8)	($107.4)	($89.0)	($50.6)	($28.0)	($41.0)	($30.7)	$0.7	($783.0)
Pepco	$80.2	$58.5	$57.2	$61.9	$58.8	$76.3	$84.2	$79.5	$66.4	$50.4	$46.0	$63.8	$1.2	$784.4
PPL	($35.7)	($29.2)	($27.6)	($14.6)	($6.1)	($4.1)	($78.8)	($65.0)	($60.0)	($71.8)	($49.0)	($47.6)	$1.6	($487.9)
PSEG	($22.2)	($16.8)	($6.8)	$4.8	($4.8)	$9.5	$31.3	$9.7	$13.4	($5.0)	$4.7	($11.9)	$1.7	$7.6
RECO	$7.2	$4.9	$4.8	$4.7	$6.3	$8.0	$11.4	$6.9	$5.2	$3.9	$3.6	$3.9	$0.1	$70.7
Total	($95.5)	($63.5)	($57.8)	($50.2)	($55.0)	($85.4)	($126.8)	($83.2)	($60.5)	($48.6)	($44.8)	($50.7)	$28.3	($793.8)

Energy Costs by Control Zone (Millions)														
2012														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$24.7	$21.1	$18.6	$16.6	$21.0	$26.6	$41.1	$32.9	$23.3	$21.3	$20.4	$23.4	$0.1	$291.3
AEP	($54.7)	($38.6)	($8.6)	($49.9)	($27.7)	($45.2)	($94.2)	($86.6)	($46.8)	($65.2)	($50.4)	($60.3)	$1.6	($626.7)
AP	$25.9	$3.2	($3.4)	$12.9	($5.0)	($28.2)	($19.8)	($30.1)	($30.5)	($19.5)	($42.5)	($27.6)	$0.5	($164.1)
ATSI	$33.8	$23.0	$16.0	($0.4)	$11.1	$18.9	$13.5	$29.3	$56.5	$40.5	$47.4	$23.7	$0.8	$314.0
BGE	$40.5	$49.1	$42.0	$20.5	$16.5	$31.9	$53.9	$42.1	$25.6	$21.1	$31.8	$30.3	$0.4	$405.7
ComEd	($101.7)	($76.6)	($59.7)	($64.4)	($63.7)	($39.9)	($8.5)	($33.7)	($56.3)	($67.5)	($80.9)	($68.4)	$1.2	($720.2)
DAY	$3.6	$7.5	$0.6	$8.6	$13.7	$4.8	$0.2	($0.5)	($5.7)	$9.1	$16.9	($3.2)	$0.2	$55.7
DEOK	$12.6	$4.7	$34.4	$23.2	$29.6	$32.4	$37.5	$6.7	$26.2	$16.3	$4.4	$9.4	$0.3	$237.7
DLCO	($6.7)	($14.1)	($11.6)	$7.6	$5.1	($4.3)	$1.2	($6.0)	($7.5)	$8.5	($13.2)	($16.4)	$1.1	($56.3)
Dominion	$30.1	$12.7	$17.3	$56.1	$47.2	$8.6	$13.1	$37.0	$31.4	$58.8	$70.1	$44.6	$0.2	$427.2
DPL	$36.3	$27.9	$22.1	$14.4	$17.8	$25.6	$38.4	$32.3	$21.7	$21.3	$37.6	$31.0	$0.2	$326.7
External	($12.3)	($15.3)	($27.9)	($11.0)	($32.5)	($49.0)	($58.3)	($19.2)	($7.3)	($17.7)	($54.9)	$5.1	$0.0	($300.2)
JCPL	$35.0	$25.3	$18.7	$10.1	$18.5	$31.1	$58.5	$36.1	$19.8	$24.2	$39.8	$35.2	$0.3	$352.5
Met-Ed	($10.9)	($21.8)	($14.0)	($19.6)	($0.1)	($15.8)	($26.1)	($7.5)	($21.0)	($23.3)	($16.8)	($9.7)	$0.2	($186.3)
PECO	($76.7)	($64.4)	($45.6)	($63.7)	($63.9)	($56.7)	($42.7)	($49.7)	($32.4)	($44.3)	($83.1)	($74.7)	$0.5	($697.3)
PENELEC	($62.2)	($18.8)	($46.0)	($18.2)	($56.9)	($55.4)	($96.2)	($56.7)	($38.8)	($35.0)	($43.7)	($46.6)	$0.2	($574.3)
Pepco	$67.9	$60.7	$49.7	$29.1	$39.5	$57.9	$63.1	$59.2	$48.1	$36.1	$29.0	$54.2	$0.4	$594.8
PPL	($39.1)	($21.9)	($31.4)	($5.9)	($9.0)	$0.6	($66.4)	($53.7)	($41.1)	($22.3)	$7.3	($11.9)	$0.5	($294.4)
PSEG	($8.6)	($13.1)	($13.3)	($2.6)	($4.7)	($2.2)	$2.5	$4.7	($12.1)	($6.8)	$19.3	$4.0	$0.5	($32.3)
RECO	$4.1	$3.4	$3.3	$3.1	$4.1	$5.2	$8.3	$5.9	$4.3	$3.8	$4.2	$4.1	$0.0	$53.8
Total	($58.6)	($45.9)	($38.7)	($33.5)	($39.3)	($53.1)	($81.0)	($57.7)	($42.6)	($40.6)	($57.3)	($53.7)	$9.1	($593.0)

FTR Volumes

This Appendix presents the data used to create Figure 8-1 in the *2012 State of the Market Report for PJM*. Each table shows the FTR bid volume, cleared volume and net bid volume by planning period. The bid volume includes the buy, sell and self-scheduled offers. The cleared volume includes the buy, sell and self-scheduled offers that clear. The net bid volume includes all bid and self-scheduled offers, excluding sell offers. The Annual Auction volume is included in June of each planning period.

Table H-1 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2003 to 2004

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-03	2,679,072	89,840	2,690,737
Jul-03	295,753	8,642	300,808
Aug-03	215,206	9,978	220,241
Sep-03	226,994	9,068	234,315
Oct-03	127,739	10,522	135,885
Nov-03	114,211	8,247	122,362
Dec-03	131,180	8,352	139,221
Jan-04	128,086	10,947	136,657
Feb-04	128,303	12,187	137,790
Mar-04	144,617	13,827	156,543
Apr-04	141,437	17,358	157,776
May-04	168,480	44,641	178,973
Total	4,501,077	243,608	4,611,308

Table H-2 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2004 to 2005

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-04	939,214	125,044	1,019,868
Jul-04	160,472	21,761	190,198
Aug-04	144,402	22,650	176,642
Sep-04	155,837	13,999	194,229
Oct-04	180,542	49,816	226,156
Nov-04	213,036	23,912	247,780
Dec-04	226,271	18,384	260,964
Jan-05	212,061	22,549	236,135
Feb-05	276,385	20,700	305,613
Mar-05	306,472	25,712	348,416
Apr-05	307,297	36,914	330,088
May-05	280,690	32,545	300,966
Total	3,402,681	413,987	3,837,056

Table H-3 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2005 to 2006

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-05	1,011,821	159,049	1,120,404
Jul-05	300,153	23,929	340,891
Aug-05	233,493	17,966	276,936
Sep-05	222,404	22,133	266,577
Oct-05	147,493	18,906	189,458
Nov-05	183,750	20,525	227,432
Dec-05	200,886	19,422	244,608
Jan-06	234,473	21,431	275,081
Feb-06	250,308	26,463	293,774
Mar-06	272,662	31,968	317,705
Apr-06	431,398	36,603	472,732
May-06	384,767	38,977	424,962
Total	3,873,608	437,372	4,450,561

Table H-4 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2006 to 2007

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-06	2,274,846	198,380	2,533,660
Jul-06	719,494	31,662	934,424
Aug-06	738,375	26,392	932,469
Sep-06	630,072	37,351	841,698
Oct-06	710,045	51,193	888,011
Nov-06	765,177	40,110	890,318
Dec-06	757,683	42,848	919,549
Jan-07	778,266	59,813	905,249
Feb-07	884,953	68,179	969,447
Mar-07	661,938	69,754	799,130
Apr-07	455,411	30,963	551,601
May-07	432,783	37,207	480,219
Total	9,809,046	693,852	11,645,776

Table H-5 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2007 to 2008

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-07	2,961,754	323,632	3,462,015
Jul-07	794,490	51,248	1,068,961
Aug-07	944,015	63,392	1,224,668
Sep-07	901,284	66,611	1,200,730
Oct-07	973,936	112,427	1,245,797
Nov-07	841,326	61,592	1,059,631
Dec-07	1,276,687	49,825	1,461,068
Jan-08	501,642	27,377	655,581
Feb-08	583,749	37,288	676,847
Mar-08	437,241	31,941	590,524
Apr-08	326,050	34,805	427,105
May-08	280,005	22,837	331,327
Total	10,822,178	882,975	13,404,256

Table H-6 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2008 to 2009

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-08	3,511,130	339,654	3,832,169
Jul-08	968,615	53,843	1,211,784
Aug-08	961,694	40,027	1,224,054
Sep-08	925,250	64,901	1,127,274
Oct-08	802,966	52,768	965,756
Nov-08	607,441	45,707	738,336
Dec-08	550,352	37,633	748,485
Jan-09	488,102	43,739	673,525
Feb-09	492,216	40,439	639,274
Mar-09	391,938	42,722	581,075
Apr-09	299,908	35,685	440,629
May-09	222,092	21,016	295,198
Total	10,221,706	818,134	12,477,560

Table H-7 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2009 to 2010

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-09	2,652,340	307,584	3,156,826
Jul-09	488,748	41,389	849,742
Aug-09	414,151	55,261	708,452
Sep-09	427,221	56,998	718,246
Oct-09	538,476	64,328	797,069
Nov-09	559,750	65,577	745,333
Dec-09	447,221	68,470	672,986
Jan-10	529,887	64,435	728,765
Feb-10	490,391	62,153	670,272
Mar-10	389,934	73,069	615,690
Apr-10	345,301	66,017	489,638
May-10	291,537	52,036	375,812
Total	7,574,956	977,318	10,528,830

Table H-8 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2010 to 2011

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-10	3,177,131	428,603	3,894,566
Jul-10	720,172	102,883	1,145,991
Aug-10	859,260	93,226	1,202,137
Sep-10	1,079,947	144,423	1,510,812
Oct-10	1,041,425	120,281	1,427,494
Nov-10	922,444	111,442	1,261,969
Dec-10	1,005,436	157,609	1,359,582
Jan-11	902,052	132,866	1,207,101
Feb-11	931,164	160,750	1,184,383
Mar-11	952,963	182,340	1,250,283
Apr-11	660,480	138,230	913,583
May-11	620,691	169,610	762,538
Total	12,873,166	1,942,261	17,120,443

Table H-9 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2011 to 2012

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-11	6,233,773	847,183	7,437,352
Jul-11	1,602,795	241,288	2,233,307
Aug-11	1,385,040	204,442	1,981,888
Sep-11	969,184	112,746	1,581,241
Oct-11	1,424,062	134,653	1,908,956
Nov-11	1,098,133	117,705	1,562,764
Dec-11	811,035	93,492	1,318,347
Jan-12	772,843	88,683	1,240,355
Feb-12	816,356	93,977	1,234,341
Mar-12	665,949	99,659	1,126,207
Apr-12	449,078	131,218	795,785
May-12	295,103	94,642	470,495
Total	16,523,352	2,259,688	22,891,036

Table H-10 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2012 to 2013

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-12	6,407,647	710,169	7,598,008
Jul-12	2,177,990	182,695	2,735,269
Aug-12	909,111	151,693	1,418,249
Sep-12	1,877,747	146,352	2,446,553
Oct-12	788,486	118,052	1,310,859
Nov-12	1,765,875	98,494	2,142,231
Dec-12	1,757,292	115,322	2,230,391
Total	15,684,148	1,522,778	19,881,561

Glossary

Aggregate
Combination of buses or bus prices.

Ancillary Services
Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Area Control Error (ACE)
Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.

Associated unit (AU)
A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.

Auction Revenue Right (ARR)
A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.

Automatic Generation Control (AGC)
An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.

Average hourly LMP
An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.

Avoidable cost rate (ACR)
The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.

Avoidable Project Investment Recovery Rate (APIR)
A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market
Energy that is generated and financially settled during real time.

Base Residual Auction (BRA)
Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

Bilateral agreement
An agreement between two parties for the sale and delivery of a service.

Black Start Unit
A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the transmission system or interconnection.

Bottled generation
Economic generation that cannot be dispatched because of local operating constraints.

Burner tip fuel price
The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.

Bus
An interconnection point.

Capacity deficiency rate (CDR)
The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.

Capacity Emergency Transfer Limit (CETL)
The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity queue
A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.

Combined Cycle (CC)
An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.

Combustion Turbine (CT)
A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.

Congestion Management Process (CMP)
A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.

Control Zone
An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Decrement Bids (DEC)
An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).

Demand deviations
Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports.

Demand Resource
A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.

Dispatch Rate
The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.

Disturbance Control Standard
A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)
Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.

Eastern Region
Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.

Economic generation
Units producing energy at an offer price less than or equal to LMP.

End-use customer
Any customer purchasing electricity at retail.

Equivalent availability factor (EAF)
The proportion of hours in a year that a unit is available to generate at full capacity.

Equivalent demand forced outage rate (EFORd)
A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.

Equivalent forced outage factor (EFOF)
The proportion of hours in a year that a unit is unavailable because of forced outages.

Equivalent maintenance outage factor (EMOF)
The proportion of hours in a year that a unit is unavailable because of maintenance outages.

Equivalent planned outage factor (EPOF)
The proportion of hours in a year that a unit is unavailable because of planned outages.

External resource
A generation resource located outside metered boundaries of the PJM RTO.

Financial Transmission Right (FTR)
A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.

Firm Point-to-Point Transmission Service
Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.

Firm Transmission Service
Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

Fixed Demand Bid
Bid to purchase a defined MW level of energy, regardless of LMP.

Fixed Resource Requirement (FRR)
An alternative method for a party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

Flowgate
A transmission facility or group of facilities that consist of the total interface between control areas, a partial interface, or an interface within a control area.

Frequently mitigated unit (FMU)
A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.

Generation Control Area (GCA) and Load Control Area (LCA)
Designations used on a NERC Tag to describe the balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms “Control Area” in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.

Generator deviations
Hourly deviations in the generator category, equal to the difference between a unit’s cleared day-ahead generation, and a unit’s hourly, integrated real-time generation.

Generation Offers
Schedules of MW offered and the corresponding offer price.

Generation owner
A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.

Gross export volume (energy)
The sum of all export transaction volume (MWh).

Gross import volume (energy)
The sum of all import transaction volume (MWh).

Gigawatt (GW)
A unit of power equal to 1,000 megawatts.

Gigawatt-day
One GW of energy flow or capacity for one day.

Gigawatt-hour (GWh)
One GWh is a gigawatt produced or consumed for one hour.

Herfindahl-Hirschman Index (HHI)
HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.

Hertz (Hz)
Electricity system frequency is measured in hertz.

HRSG
Heat recovery steam generator. An air-to-steam heat exchanger.

Increment offers (INC)
Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.

Incremental Auction
Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.

Inframarginal unit
A unit that is operating, with an accepted offer that is less than the clearing price.

Installed capacity
Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.

Load
Demand for electricity at a given time.

Load Management
Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

Load-serving entity (LSE)
Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.

Locational Deliverability Area (LDA)
Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Marginal unit
The last, highest cost, generation unit to supply power under a merit order dispatch system.

Market-clearing price
The price that is paid by all load and paid to all suppliers.

Market participant
A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.

Market user interface
A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.

Maximum daily starts
The maximum number of times a unit can start in a day. An operating parameter incorporated in a unit's schedule.

Maximum weekly starts
The maximum number of times a unit can start in a week. An operating parameter incorporated in a unit's schedule.

Mean
The arithmetic average.

Median
The midpoint of data values. Half the values are above and half below the median.

Megawatt (MW)
A unit of power equal to 1,000 kilowatts.

Megawatt-day
One MW of energy flow or capacity for one day.

Megawatt-hour (MWh)
One MWh is a megawatt produced or consumed for one hour.

Megawatt-year
One MW of energy flow or capacity for one calendar year.

Minimum down time
The minimum amount of time that a unit has to stay off, or "down," before starting again. An operating parameter incorporated in a unit's schedule.

Minimum run time
The minimum amount of time that a unit has to stay on before shutting down. An operating parameter incorporated in a unit's schedule.

Monthly CCM
The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).

Multimonthly CCM
The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).

Net excess (capacity)
The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.

Net exchange (capacity)
Capacity imports less exports.

Net interchange (energy)
Gross import volume less gross export volume in MWh.

Network Transmission Service
Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.

Noneconomic generation
Units producing energy at an offer price greater than the LMP.

Non-Firm Transmission Service
Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.

North American Electric Reliability Council (NERC)
A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.

Off peak
For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.

On peak
For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.

Opportunity cost
In general, the value of the opportunity foregone when a specific action is taken. In the ancillary services markets, the difference in compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received had it provided energy instead.

Parameter-limited schedule
A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.

PJM member

Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.

PJM planning year

The calendar period from June 1 through May 31.

Point of Receipt (POR) and Point of Delivery (POD)

Designations used on a transmission reservation. The designations, when combined, determine the transmission reservations' market path.

Pool-scheduled resource

A generating resource that the seller has turned over to PJM for scheduling and control.

Price duration curve

A graphic representation of the percent of hours that a system's price was at or below a given level during the year.

Price-sensitive bid

Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.

Primary operating interfaces

Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.

Ramp-limited desired (MW)

The achievable MW based on the UDS requested ramp rate.

Regional Transmission Expansion Planning (RTEP) Protocol

The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.

Reliability*First* Corporation

Reliability*First* Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).

Reliability Pricing Model (RPM)

PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

Selective catalytic reduction (SCR)

NO_x reduction equipment usually installed on combined-cycle generators.

Self-scheduled generation

Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.

Shadow price

The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.

Short-Term Resource Procurement Target

The Short-Term Resource Procurement Target is equal to 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the First Incremental Auction, and 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the Second Incremental Auction. The stated rationale for this administrative reduction in demand is to permit short lead time resource procurement in later auctions for the delivery year.

Sources and sinks

Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.

Spot Import Transmission Service

Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.

Spot market

Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.

Static Var compensator

A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.

Summer Net Capability

The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load.

Summer conditions shall reflect the 50% probability of occurrence (approximated by the mean) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available.

For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday.

For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

The determination of the Summer Net Capability of hydro and pumped storage units shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability.

For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

Supply deviations

Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.

Synchronized reserve

Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.

System installed capacity

System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.

System lambda

The cost to the PJM system of generating the next unit of output.

Temperature-humidity index (THI)

A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: THI = T_d – (0.55 – 0.55RH) * (T_d - 58) if T_d is > 58; else THI= T_d (where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.)

Transmission Adequacy and Reliability Assessment (TARA)

An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.

Turn down ratio

The ratio of dispatchable megawatts on a unit's schedule. Calculated by a unit's economic maximum MW divided by its economic minimum MW. An operating parameter of a unit's schedule.

Unforced capacity

Installed capacity adjusted by forced outage rates.

Western region

Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, AP, ComEd, DLCO, and DAY transmission zones.

Wheel-through

An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.

Winter Weather Parameter (WWP)

WWP is wind speed adjusted temperature. WWP is defined as: WWP = T_d - (0.5 * (WIND -10) if WIND > 10 mph; WWP = T_d if WIND <= 10 mph (where T_d is the dry-bulb temperature and WIND is the wind speed.)

Zone

See "Control zone" (above).

List of Acronyms

AC2	Advanced Control Center
ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
ALTE	Eastern Alliant Energy Corporation
ALTW	Western Alliant Energy Corporation
AMI	Advanced Metering Infrastructure
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
APIR	Avoidable Project Investment Recovery
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ASO	Ancillary Service Optimization
ATC	Available transfer capability
ATSI	American Transmission Systems, Inc.
AU	Associated unit
BA	Balancing authority
BAAL	Balancing authority ACE limit
BACT	Best Available Control Technology
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
BOR	Balancing Operating Reserve
BRA	Base Residual Auction
BSSWG	Black Start Services Working Group
BTU	British thermal unit
C&I	Commercial and industrial customers
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDS	Cost Development Subcommittee
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company

CIDS	Critical Infrastructure Protocol
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
CMP	Congestion management process
CMR	Congestion Management Report
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator
CPI	Consumer Price Index
CPL	Carolina Power & Light Company
CPS	Control performance standard
CRC	Central Repository for Curtailments
CRF	Capital Recovery Factor
CSAPR	Cross State Air Pollution Rule
CSP	Curtailment service provider
CT	Combustion turbine
CTR	Capacity transfer right
DASR	Day-Ahead Scheduling Reserve
DAY	Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLC	Direct Load Control
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DRS	Demand Response Subcommittee
DRSDTF	Demand Response Subzonal Dispatch Task Force
DSR	Demand-side response
DUK	Duke Energy Corporation
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EE	Energy Efficiency
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EFORp	Equivalent forced outage rate during peak hours
EHV	Extra-high-voltage
EIS	Environmental Information Services
EKPC	East Kentucky Power Cooperative, Inc.
ELRP	Economic Load Response Program
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EMS	Energy management system
EPA	Environmental Protection Agency

EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
ESP	Electrostatic Precipitators (Baghouses)
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FFE	Firm flow entitlement
FGD	Flue-gas desulfurization
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FSL	Firm Service Load
FTR	Financial Transmission Right
FTRTF	Financial Transmission Rights Task Force
GACT	Generally Available Control Technology
GCA	Generation control area
GE	General Electric Company
GHG	Greenhouse Gas
GLD	Guaranteed Load Drop
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HE	Hour Ending
HEDD	NJ High Energy Demand Day
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
IARR	Incremental ARRs
IA	RPM Incremental Auction
ICAP	Installed capacity
ICCP	Inter-Control Center Protocol
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
ITSCED	Intermediate Term Security Constrained Economic Dispatch
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units

JRCA	Joint Reliability Coordination Agreement
KV	KiloVolt
KDAEV	Known Day-Ahead Error Value
LAER	Lowest Achievable Emissions Rate
LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LIND	Linden Variable Frequency Transformer (VFT)
LM	Load management
LMP	Locational marginal price
LMTF	Load Management Task Force
LOC	Lost opportunity cost
LPC	Locational Pricing Calculator
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MACT	Maximum Achievable Control Technology
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MATS	Mercury and Air Toxics Standards rule
MCP	Market-clearing price
MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MIC	Market Implementation Committee
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
MIL	Mandatory interruptible load
MIS	Market information system
MISO	Midwest Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MP	Market participant
MRC	Markets and reliability committee
MRT	Minimum run time
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board
NBT	Net Benefits Test
NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC line

NERC	North American Electric Reliability Council
NESHAP	National Emission Standards for Hazardous Air Pollutants
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NJDEP	New Jersey Department of Environmental Protection
NNL	Network and native load
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OPSI	Organization of PJM States, Inc.
OMC	Outside Management Control
OVEC	Ohio Valley Electric Corporation
ORS	NERC Operating Reliability Subcommittee
PAR	Phase angle regulator
PATH	Potomac – Appalachian Transmission Highline
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point

PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/LIND	The interface between PJM and the New York System Operator over the Linden VFT line
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area

PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak Load Contribution
PLS	Parameter limited schedule
PMSS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPB	Parts per billion
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSD	Prevention of Significant Deterioration
PSN	PSEG north
PSNC	PSEG north central
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCF	Reciprocal Coordinated Flowgate
RCIS	Reliability Coordinator Information System
REC	Renewable Energy Credit
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility
RMCCP	Regulation market capability clearing price
RMCP	Regulation market-clearing price
RMPCP	Regulation market performance clearing price
RMR	Reliability Must Run
ROFR	Right of First Refusal
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RRMSE	Relative Root Mean Squared Error
RSI	Residual supply index
RSI_x	Residual supply index, using "x" pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
SAA	Symmetrical Additive Adjustment
SCE&G	South Carolina Energy and Gas
SCED	Security Constrained Economic Dispatch
SCPA	South central Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea

SERC	SERC Reliability Corporation
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
SNCR	Selective Non-Catalytic Reduction
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
STRPTAS	Short Term Resource Procurement Applicable Share
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TISTF	Transactions Issues Senior Task Force
TLR	Transmission loading relief
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force
TPY	Tons Per Year
TrAIL	Trans – Allegheny Interstate Line
TSIN	NERC Transmission System Information Network
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VFT	Variable frequency transformer
VOCs	Volatile Organic Compounds
VOM	Variable operation and maintenance expense
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion
WWP	Winter Weather Parameter
XEFORd	EFORd modified to exclude OMC outages