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State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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PREFACE

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2011 Quarterly State of the Market Report for PJM: January through September*.

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

2 OATT Attachment M § II(f).

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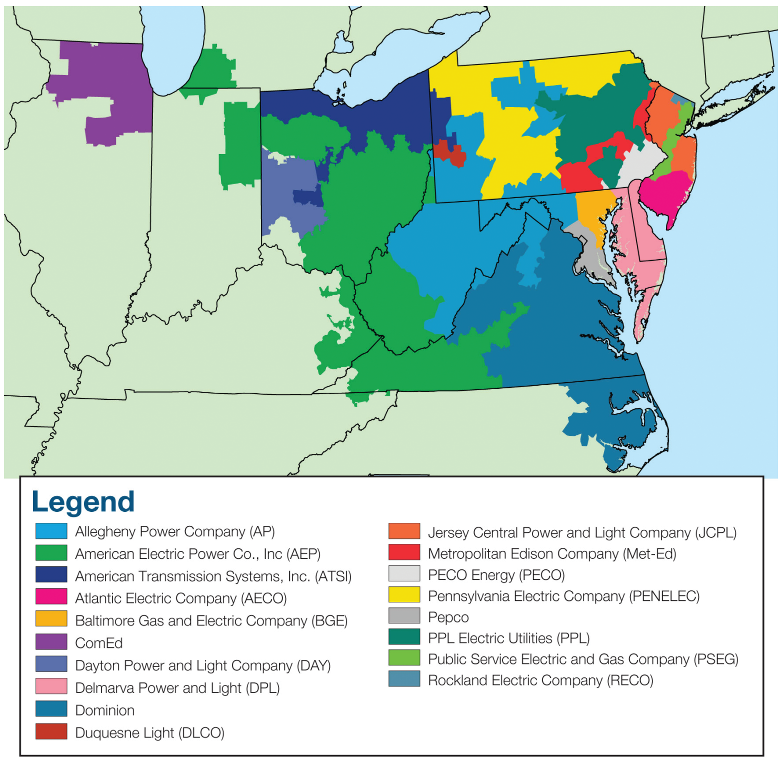
SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2011, had installed generating capacity of 179,572 megawatts (MW) and more than 750 market buyers, sellers and traders of electricity[1] in a region including more than 58 million people[2] in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[3] In the first nine months of 2011, PJM had total billings of $28.8 billion. As part of that 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 18 control zones[4]



1 See <http://pjm.com/about-pjm/who-we-are/company-overview.aspx>.
2 See <http://pjm.com/about-pjm/who-we-are/company-overview.aspx>.
3 See the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2011.
4 On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined the PJM footprint.

PJM Market Background

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 June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this *2011 Quarterly State of the Market Report: January through September* include the integration of the ATSI zone for the period from June through September.

5 See also the *2010 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."
6 Analysis of 2011 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. 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 2011, see the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2011, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

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

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness 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 test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between ownership among multiple entities and the market demand and it does so using actual market conditions reflecting both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

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

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

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

The MMU concludes the following for the first nine months of 2011:

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 the first nine months of 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1200 with a minimum of 889 and a maximum of 1564 in the January through September period of 2011.

- 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 test, used to test local market structure, indicate the existence of market power in a number of 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 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.

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

7 OATT Attachment M

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: Local Market	Competitive	
Market Performance	**Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. For 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.

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

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

- 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.

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.

- 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 a definition of DR which permits an inferior product to substitute for capacity.

Table 1-3 The Regulation Market results were not competitive[9]

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 91 percent of the hours in the first nine months of 2011.

- Participant behavior was evaluated as competitive 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, despite competitive participant behavior, because the 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.

- Market design was evaluated as flawed because the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

9 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 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. 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.

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 and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 56 percent of the hours in the first nine months of 2011.
- 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 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 the market failed the three pivotal supplier test in only a limited number of hours.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, about ten 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 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 in the first nine months of 2011.
- 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.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[10] 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.[11]

10 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).

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

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 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.[12] The MMU has direct, confidential access to the FERC.[13] The MMU may also refer matters to the attention of State commissions.[14]

The MMU monitors market behavior for violations of FERC Market Rules.[15] 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,[16] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[17] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[18]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[19] 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[20] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[21] 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, or participates as a party or provides 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 (CDG).[22] 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.[23]

12 OATT Attachment M § IV.
13 OATT Attachment M § IV.K.3.
14 OATT Attachment M § IV.H.
15 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.").
16 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. 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.
17 OATT Attachment M § II(h-1).
18 OATT Attachment M § IV.C.
19 OATT Attachment M § IV.I.1.
20 *Id.*
21 *Id.*
22 *See* OATT Attachment M–Appendix § II.A.
23 OATT Attachment M–Appendix § II.E.

The MMU also reviews operational parameter limits included with unit offers,[24] evaluates compliance with the requirement to offer into the energy and capacity markets,[25] evaluates the economic basis for unit retirement requests,[26] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[27]

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.[28] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[29] 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.[30] 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.[31] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[32]

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,"[33] 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 *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

The additional recommendation from the *2011 Quarterly State of the Market Report for PJM: January through June,* that the Synchronized Reserve Market design be modified to address the issue of units which offer and clear synchronized reserve but fail to provide synchronized reserve when an actual spinning event occurs, also remains an MMU recommendation. (See Section 6, "Ancillary Services", Page 154.)

Highlights

The following presents highlights of each of the sections of the *2011 Quarterly State of the Market Report for PJM: January through September*, including the new analysis that has been included in this report since the *2010 State of the Market Report for PJM*:

Section 2, Energy Market, Part 1

- Average offered supply increased by 11,535, or 7.4 percent, from 156,259 MW in the third quarter of 2010 to 167,794 MW in the third quarter of 2011. The large increase in offered supply was the result of the integration of the ATSI zone in the second quarter, plus the addition of 3,639 MW of nameplate capacity to PJM in 2011. This includes three large plants (over 550 MW) that have started generating in PJM since January 1, 2011. The increases in supply were partially offset by the deactivation of twelve units (738 MW) since January 1, 2011. (See Page 19.)

- The PJM system peak load for the third quarter of 2011 was 158,016 MW in the HE 1700 on July 21, 2011, which was 21,556 MW, or 15.8 percent, higher than the PJM peak load for the third quarter of 2010, which was 136,460 MW in the HE 1700 on July 6, 2010.[34] The ATSI transmission zone accounted for 13,953 MW in the peak hour of third quarter 2011. The peak load excluding the ATSI transmission zone was 144,063 MW, also occurring on July 21, 2011, HE 1700, an increase of 7,603 MW from the 2010 peak load. (See Page 19 and 20.)

- PJM average real-time load in the first nine months of 2011 increased by 3.3 percent from the first nine months of 2010, from 81,068 MW to 83,762 MW. The PJM average real-time load in the first nine months of 2011 would have decreased by 1.2 percent from the first nine months of 2010, from 81,068 MW to 80,135 MW, if the ATSI transmission zone were excluded. (See Page 26 and 27.)

24 OATT Attachment M–Appendix § II.B.
25 OATT Attachment M–Appendix § II.C.
26 OATT Attachment M–Appendix § IV.
27 OATT Attachment M–Appendix § VII.
28 OATT Attachment M § IV.D.
29 *Id.*
30 *Id.*
31 *Id.*
32 OATT Attachment M § VI.A.
33 18 CFR § 35.28(g)(3)(ii)(A); *see also* OATT Attachment M § IV.D.

34 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2010 State of the Market Report for PJM*, Appendix G, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

- PJM average day-ahead load, including DECs, in the first nine months of 2011 increased by 0.2 percent from the first nine months of 2010, from 92,683 MW to 92,828 MW. PJM average day-ahead load, including DECs, in the first nine months of 2011 would have been 3.8 percent lower than in the first nine months of 2010, from 92,683 MW to 89,146 MW if the ATSI transmission zone were excluded. (See Page 28.)

- PJM average day-ahead load, excluding virtuals, in the first nine months of 2011 increased by 6.7 percent from the first nine months of 2010, from 76,455 MW to 81,593 MW. PJM average day-ahead load, excluding virtuals, in the first nine months of 2011 would have increased by 2.0 percent from the first nine months of 2010, from 76,455 MW to 78,017 MW if the ATSI transmission zone were excluded. (See Page 28.)

- PJM average real-time generation in the first nine months of 2011 increased by 3.4 percent from the first nine months of 2010, from 84,086 MW to 86,963 MW. PJM average real-time generation in the first nine months of 2011 would have decreased 0.6 percent from the first nine months of 2010, from 84,086 MW to 83,573 MW if the ATSI transmission zone were excluded. (See Page 30.)

- PJM average day-ahead generation, excluding virtuals, in the first nine months of 2011 increased by 4.0 percent from the first nine months of 2010, from 84,790 MW to 88,220 MW. The PJM average day-ahead generation, excluding virtuals, in the first nine months of 2011 would have decreased by 0.1 percent from the first nine months of 2010, from 84,790 MW to 84,691 MW if the ATSI transmission zone were excluded. (See Page 30.)

- PJM Real-Time Energy Market prices decreased in the first nine months of 2011 compared to the first nine months of 2010. The load-weighted average LMP was 0.9 percent lower in the first nine months of 2011 than in the first nine months of 2010, $49.48 per MWh versus $49.91 per MWh. (See Page 32.)

- PJM Day-Ahead Energy Market prices decreased in the first nine months of 2011 compared to the first nine months of 2010. The load-weighted average LMP was 1.6 percent lower in the first nine months of 2011 than in the first nine months of 2010, $48.34 per MWh versus $49.12 per MWh. (See Page 34.)

- Levels of offer capping for local market power remained low. In the first nine months of 2011, 0.9 percent of unit hours and 0.3 percent of MW were offer capped in the Real-Time Energy Market and 0.0 percent of unit hours and 0.0 percent of MW were offer capped in the Day-Ahead Energy Market. (See Page 21.)

- Of the 176 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first nine months of 2011, 58 (33 percent) qualified in all nine months, and 20 (11 percent) qualified in only one month of 2011. (See Page 23.)

- The overcollected portion of transmission losses decreased in the first nine months of 2011 to $502.1 million, or 43.6 percent of the total losses compared to $639.9 million or 50.8 percent of total losses in the same period in 2010. (See Page 44.)

- In the first nine months of 2011, the total MWh of load reduction under the Economic Load Response Program decreased by 43,965 MWh compared to the same period in 2010, from 58,280 MWh in 2010 to 14,315 MWh in 2011, a 75 percent decrease. Total payments under the Economic Program decreased by $779,756, from $2,677,937 in 2010 $1,898,180 in 2011, a 29 percent decrease. (See Page 53 and 54.)

- In the first nine months of 2011, total capacity payments to demand response resources under the PJM Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, increased by $19.5 million, or 5.4 percent, compared to the same period in 2010, from $362 Million in 2010 to $381 Million in 2011. (See Page 54.)

Section 3, Energy Market, Part 2

- Net revenue performance was the result of capacity market prices, which declined in all LDAs except rest of RTO and energy market prices which were lower for most zones. Combustion turbine (CT) net revenues were lower in ten zones and higher in six zones, including four zones where net revenues increased by more than 20 percent. Combined Cycle (CC) net revenues were lower in eleven zones and higher in five zones, including three zones where net revenues increased by more than 20 percent. Coal Plant (CP) net revenues were lower in twelve zones and higher in four zones, including one zone where net revenues increased by more than 20 percent. (See Page 60 and 61.)

- There were no scarcity pricing events in the first nine months of 2011 under PJM's current Emergency Action based scarcity pricing rules. (See Page 86.)

- Operating reserve charges increased $83,751,028, or 20.5 percent, from $408,267,759 in the first nine months of 2010, to $492,018,787 in the first nine months of 2011. Reliability credits decreased $7,716,442, or 9.4 percent, in the first nine months of 2011 compared to the first nine months of 2010, and deviation credits increased $263,011,867, or 184.3 percent. (See Page 87.)

- Reliability charges were $74,733,573, 15.6 percent of all balancing operating reserve charges for the first nine months 2011, a decrease of $7,801,659 or 9.4 percent from the first nine months of 2010. Deviation charges were $405,744,328, or 84.4 percent in the first nine months of 2011, an increase of $262,622,763, or 183.5 percent from the first nine months of 2010. (See Page 88.)

- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 29.7 percent of total operating reserve credits in the first nine months of 2011, compared to 36.4 percent in the first nine months of 2010. In the first nine months of 2011, the top generation owner received 22.7 percent of the total operating reserve credits paid. (See Page 94.)

- The regional concentration of balancing operating reserves for the first nine months of 2011 is higher than the first nine months of 2010, with 28.7 percent of the credits paid to units operating in the Dominion zone, 21.8 percent in the PSEG zone, and 10.1 percent in the AEP zone. (See Page 93.)

- In the first nine months of 2011, coal units provided 48.2 percent, nuclear units 33.8 percent and gas units 13.8 percent of total generation. Compared to the first nine months of 2010, generation from coal units decreased 0.3 percent, and generation from nuclear units increased 1.5 percent, while generation from natural gas units increased 24.4 percent, and generation from oil units decreased 29.5 percent. (See Page 71.)

- At the end of September 2011, 86,864 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 180,000 MW in 2011 since the June 1, 2011, ATSI integration. Wind projects account for approximately 39,459 MW of capacity, 45.4 percent of the capacity in the queues and combined-cycle projects account for 26,785 MW, 30.8 percent, of the capacity in the queues. (See Page 72.)

- Three large plants (over 550 MW) started generating in PJM since January 1, 2011. These include York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, and Longview Power in the APS zone. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 3,639 MW of nameplate capacity was added in PJM in 2011 (excluding the ATSI zone additions), the most since 2002. (See Page 72.)

Section 4, Interchange Transactions

- On June 1, 2011 at 0100, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. As a result, the First Energy (FE) Interface and the MICHFE Interface Pricing Point were eliminated. (See Page 114.)

- Real-time net exports decreased to -7,113.9 GWh during the first nine months of 2011 from -7,411.9 GWh during the first nine months of 2010. Day-ahead net imports were 9,066.0 GWh compared to net exports of -6,657.8 GWh during the first nine months of 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first nine months of 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. (See Page 108 and 110.)

- The direction of power flows was not consistent with real-time energy market price differences in 56 percent of hours at the border between PJM and MISO and in 47 percent of hours at the border between PJM and NYISO during the first nine months of 2011. (See Page 115 and 116.)

- During the first nine months of 2011, net scheduled interchange was -4,176 GWh and net actual interchange was -4,524 GWh, a difference of 348 GWh or 8.3 percent, an increase from 4.8 percent during the first nine months of 2010 and 5.2 percent for the calendar year 2010. This difference is system inadvertent. (See Page 119.)

- PJM initiated 58 TLRs during the first nine months of 2011, a reduction from the 96 TLRs in the first nine months of 2010. (See Page 121.)

- The average daily volume of up-to congestion bids increased from 376 bids per day, for the period between March 1, 2009 through May 14, 2010, to 762 bids per day for the period between May 15, 2010 through September 16, 2010, to 1,987 bids per day for the period between September 17, 2010 through September 30, 2011. A significant increase in bid volume occurred following the September 17, 2010, modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids. (See Page 121 through 123.)

- Total uncollected congestion charges during the first nine months of 2011 were $11,942, compared to $2.9 million for the first nine months of 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present. (See Page 128.)

- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were $1.3 million during the first nine months of 2011, an increase from $290,515 in the first nine months of 2010. (See Page 104.)

Section 5, Capacity Markets

- The 2012/2013 RPM Second Incremental Auction and the 2013/2014 First Incremental Auction were run in the third quarter of 2011. In the 2012/2013 RPM Second Incremental Auction, the RTO resource clearing price was $13.01 per MW-day, and the EMAAC resource clearing price was $48.91 per MW-day. In the 2013/2014 RPM First Incremental Auction, the RTO resource clearing price was $20.00 per MW-day, the EMAAC resource clearing price was $178.85 per MW-day, and the SWMAAC resource clearing price was $54.82 per MW-day. (See Page 139.)

- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2014/2015 delivery year. (See Page 135.)

- Capacity in the RPM load management programs totals 9,681.0 MW for June 1, 2011. (See Page 138.)

- Annual weighted average capacity prices increased from a Capacity Credit Market (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 $127.05 per MW-day in 2014. (See Page 141.)

- Average PJM equivalent demand forced outage rate (EFORd) increased from 6.7 percent in the first nine months of 2010 to 7.6 percent in the first nine months of 2011. The increase in system EFORd resulted primarily from an increase in EFORd for steam units, offset by reductions in EFORd for combined cycle units and combustion turbine units. (See Page 143.)

- The PJM aggregate equivalent availability factor (EAF) decreased from 86.4 percent in the first nine months of 2010 to 84.8 percent in the first nine months of 2011. The equivalent maintenance outage factor (EMOF) remained constant at 2.8 percent in the first nine months of 2010 and the first nine months of 2011, the equivalent planned outage factor (EPOF) increased from 6.2 percent from the first nine months of 2010 to 7.2 percent in the first nine months of 2011, and the equivalent forced outage factor (EFOF) increased from 4.6 percent in the first nine months of 2010 to 5.2 percent in the first nine months of 2011. (See Page 142.)

Section 6, Ancillary Services

- The load weighted average Regulation Market clearing price, including opportunity cost, for the first nine months of 2011 was $17.03 per MW.[35] This was a decrease of $2.25, or 12 percent, from the average price for regulation during the same period in 2010. The total cost of regulation decreased by $1.21 from $33.92 per MW for the first nine months of 2010, to $32.71, or 3.6 percent. For the first nine months of 2011 the load weighted Regulation Market clearing price was only 52 percent of the total regulation cost per MW, compared to 57 percent of the total costs of regulation per MW in the first nine months of 2010. (See Page 160.)

35 The term "load weighted" in the Regulation Market refers to regulation MW weighted.

- The load weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was $12.00 per MW in the first nine months of 2011, a $0.49 per MW increase from the same period in 2010.[36] The total cost of synchronized reserves per MWh for the first nine months of 2011 was $14.21, a 4.0 percent decrease from the total cost of synchronized reserves ($14.81) during the first nine months of 2010. The load weighted average Synchronized Reserve Market clearing price was 73 percent of the load weighted average total cost per MW of synchronized reserve in the first nine months of 2011, up from 70 percent in the same time period of 2010. (See Page 168.)

- The load weighted DASR market clearing price in the first nine months of 2011 was $1.04 per MW. In the first nine months of 2010, the load weighted price of DASR was $0.18 per MW. The year over year increase in the load weighted average price per MW of DASR was attributable to several days of high DASR prices in June, July and August. (See Page 170.)

- Black start zonal charges in the first nine months of 2011 ranged from $0.02 per MW in the ATSI zone to $0.75 per MW in the PSEG zone. (See Page 171.)

Section 7, Congestion

- Congestion costs in the first nine months of 2011 decreased by 25.7 percent over congestion costs in the first nine months of 2010 (Table 7-2). (See Page 177.)

- Net balancing congestion costs were -$192.9 million in the first nine months of 2011 and -$169.8 million in the first nine months of 2010. Negative balancing congestion costs indicate that the congestion payments in the Day-Ahead Market exceeded congestion payments in the Real-Time Market. (See Page 179.)

- Measured in terms of the total congestion bill, calculated by subtracting generation congestion credits from load congestion payments plus explicit congestion costs by zone, ComEd was the most congested zone in the first nine months of 2011, despite having, on average, negative congestion components in zonal LMPs. Measured in these terms, ComEd accounted for 22.2 percent of the total congestion cost (Table 7-21). In the first nine months of 2010, AP was the most congested zone, accounting for 19.8 percent of the total net congestion cost (Table 7-22.)[37] (See Page 190.)

- Monthly congestion costs in the first nine months of 2011 were lower than monthly congestion costs in the same period in 2010, with the exception of January and March (Table 7-3). (See Page 177.)

- PJM backbone transmission projects are a subset of significant baseline transmission upgrades. The backbone upgrades are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. (See Page 176.)

  On August 18, 2011, the PJM Board of Managers instructed Pepco Holdings, Inc. (PHI) that the MAPP in-service date of 2015 was moved to 2019-2021, and advised PHI to sustain efforts needed to allow the MAPP project to be resumed.

  In October 2011, the Rapid Response Team for Transmission, a federal interagency team led by the White House Council on Environmental Quality, included the Susquehanna-Roseland power line project in its list of seven transmission line projects for rapid review and permit process.

Section 8, Financial Transmission Rights and Auction Revenue Rights

- On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined the PJM footprint. Network Service users and Firm Transmission Customers in the ATSI Control Zone participated in the Annual ARR Allocation and the Annual FTR Auction for the 2011 to 2012 planning period. (See Page 196.)

- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2011 to 2012 planning period increased by 84 percent from 580,753 MW to 1,067,014

36 The term “load weighted” in the Synchronized Reserve Market refers to synchronized reserve MW weighted.

37 Since the *2008 State of the Market Report* the MMU has provided load congestion payments and generation congestion credits calculated as constraint specific net congestion costs by organization by zone. Load congestion payments and generation congestion credits are calculated by constraint for each zone. Within each zone, where constraint specific congestion payments and credits are of the same sign, the payments and credits are netted by organization within the zone. For a specific constraint, this results in an organization being assigned either net generation congestion credits or net load congestion charges within a zone. All net generation credits and net congestion payments are summed across organizations within each zone to determine the total congestion generation credits, total congestion load charges and total net congestion charges by zone. These results are used to calculate system-wide total congestion generation credits and total congestion load charges.

MW compared to the first four months of the 2010 to 2011 planning period. (See Page 198.)

- FTRs were paid at 84.9 percent of the target allocation level for the full 2010 to 2011 planning period and 90.9 percent for the first four months of the 2011 to 2012 planning period. (See Page 206.)

- FTRs were profitable overall and were profitable for both physical and financial entities in the first nine months of 2011. Total FTR profits were $363.7 million for physical entities and $147.2 million for financial entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities. (See Page 205.)

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 1-7 provides the average price and total revenues paid, by component for the January through September period for 2010 and 2011.

Table 1-7 shows that Energy, Capacity and Transmission Service Charges represent the three largest components of the total price per MWh of wholesale power, contributing 96.1 percent of the total price per MWh in the first nine months of 2011. The cost of energy was 74.3 percent of the total price per MWh in 2011, the cost of capacity was 15.3 percent and the cost of transmission service was 6.5 percent in the first nine months of 2011.

The total per MWh price of wholesale power for the first nine months of 2011, $66.58, was 2.8 percent lower than total per MWh price of wholesale power for the first nine months of 2010, $67.83. This decrease in the total price per MWh is largely attributable to the 13.0 percent decrease which was the result of a reduction in the capacity price between 2010 and 2011.

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 Load Weighted 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 Charge 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 (AC2) 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]

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.

- 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]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[48]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[49]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[50]

Table 1-7 Total price per MWh by category and total revenues by category: January through September of 2010 and 2011 (See 2010 SOM, Table 1-7)

Category	2010 (Jan-Sep) $/MWh	2011 (Jan-Sep) $/MWh	Percent Change $/MWh	2010 (Jan-Sep) Percent	2011 (Jan-Sep) Percent
Energy	$49.91	$49.47	(0.9%)	73.6%	74.3%
Capacity	$11.71	$10.19	(13.0%)	17.3%	15.3%
Transmission Service Charges	$3.93	$4.30	9.4%	5.8%	6.5%
Operating Reserves (Uplift)	$0.76	$0.90	18.2%	1.1%	1.3%
PJM Administrative Fees	$0.37	$0.38	2.2%	0.6%	0.6%
Reactive	$0.36	$0.38	7.3%	0.5%	0.6%
Regulation	$0.37	$0.36	(5.3%)	0.6%	0.5%
Transmission Enhancement Cost Recovery	$0.18	$0.28	55.9%	0.3%	0.4%
Synchronized Reserves	$0.06	$0.09	54.1%	0.1%	0.1%
Transmssion Owner (Schedule 1A)	$0.09	$0.09	1.6%	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.01	$0.07	402.8%	0.0%	0.1%
Black Start	$0.02	$0.02	21.9%	0.0%	0.0%
NERC/RFC	$0.02	$0.02	(8.2%)	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(3.2%)	0.0%	0.0%
Load Response	$0.01	$0.01	(11.0%)	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	25.9%	0.0%	0.0%
Total	$67.83	$66.58	(1.8%)	100.0%	100.0%

45 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6..
46 OATT Schedule 6A.
47 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
48 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
49 OA Schedule 1 § 3.6.
50 OA Schedule 1 § 5.3b.

SECTION 2 – ENERGY MARKET, PART 1

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 January through September of 2011, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2011.

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 the first nine months of 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1200 with a minimum of 889 and a maximum of 1564 in the January through September period of 2011.

- 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 test, used to test local market structure, indicate the existence of market power in a number of 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 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.

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]

Highlights

- Average offered supply increased by 11,535, or 7.4 percent, from 156,259 MW in the third quarter of 2010 to 167,794 MW in the third quarter of 2011. The large increase in offered supply was the result of the integration of the ATSI zone in the second quarter, plus the addition of 3,639 MW of nameplate capacity to PJM in 2011. This includes three large plants (over 550 MW) that have started generating in PJM since January 1, 2011. The increases in supply were partially offset by the deactivation of twelve units (738 MW) since January 1, 2011.

- The PJM system peak load for the third quarter of 2011 was 158,016 MW in the HE 1700 on July 21, 2011, which was 21,556 MW, or 15.8

1 Analysis of 2011 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, PJM integrated the American Transmission Systems, Inc. (ATSI) 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 the *2010 State of the Market Report for PJM*, Volume II, 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.

percent, higher than the PJM peak load for the third quarter of 2010, which was 136,460 MW in the HE 1700 on July 6, 2010.[4] The ATSI transmission zone accounted for 13,953 MW in the peak hour of third quarter 2011. The peak load excluding the ATSI transmission zone was 144,063 MW, also occurring on July 21, 2011, HE 1700, an increase of 7,603 MW from the 2010 peak load.

- PJM average real-time load in the first nine months of 2011 increased by 3.3 percent from the first nine months of 2010, from 81,068 MW to 83,762 MW. The PJM average real-time load in the first nine months of 2011 would have decreased by 1.2 percent from the first nine months of 2010, from 81,068 MW to 80,135 MW, if the ATSI transmission zone were excluded.

- PJM average day-ahead load, including DECs, in the first nine months of 2011 increased by 0.2 percent from the first nine months of 2010, from 92,683 MW to 92,828 MW. PJM average day-ahead load, including DECs, in the first nine months of 2011 would have been 3.8 percent lower than in the first nine months of 2010, from 92,683 MW to 89,146 MW if the ATSI transmission zone were excluded.

- PJM average day-ahead load, excluding virtuals, in the first nine months of 2011 increased by 6.7 percent from the first nine months of 2010, from 76,455 MW to 81,593 MW. PJM average day-ahead load, excluding virtuals, in the first nine months of 2011 would have increased by 2.0 percent from the first nine months of 2010, from 76,455 MW to 78,017 MW if the ATSI transmission zone were excluded.

- PJM average real-time generation in the first nine months of 2011 increased by 3.4 percent from the first nine months of 2010, from 84,086 MW to 86,963 MW. PJM average real-time generation in the first nine months of 2011 would have decreased 0.6 percent from the first nine months of 2010, from 84,086 MW to 83,573 MW if the ATSI transmission zone were excluded.

- PJM average day-ahead generation, excluding virtuals, in the first nine months of 2011 increased by 4.0 percent from the first nine months of 2010, from 84,790 MW to 88,220 MW. The PJM average day-ahead generation, excluding virtuals, in the first nine months of 2011 would have decreased by 0.1 percent from the first nine months of 2010, from 84,790 MW to 84,691 MW if the ATSI transmission zone were excluded.

- PJM Real-Time Energy Market prices decreased in the first nine months of 2011 compared to the first nine months of 2010. The load-weighted average LMP was 0.9 percent lower in the first nine months of 2011 than in the first nine months of 2010, $49.48 per MWh versus $49.91 per MWh.

- PJM Day-Ahead Energy Market prices decreased in the first nine months of 2011 compared to the first nine months of 2010. The load-weighted average LMP was 1.6 percent lower in the first nine months of 2011 than in the first nine months of 2010, $48.34 per MWh versus $49.12 per MWh.

- Levels of offer capping for local market power remained low. In the first nine months of 2011, 0.9 percent of unit hours and 0.3 percent of MW were offer capped in the Real-Time Energy Market and 0.0 percent of unit hours and 0.0 percent of MW were offer capped in the Day-Ahead Energy Market.

- Of the 176 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first nine months of 2011, 58 (33 percent) qualified in all nine months, and 20 (11 percent) qualified in only one month of 2011.

- The overcollected portion of transmission losses decreased in the first nine months of 2011 to $502.1 million, or 43.6 percent of the total losses compared to $639.9 million or 50.8 percent of total losses in the same period in 2010.

- In the first nine months of 2011, the total MWh of load reduction under the Economic Load Response Program decreased by 43,965 MWh compared to the same period in 2010, from 58,280 MWh in 2010 to 14,315 MWh in 2011, a 75 percent decrease. Total payments under the Economic Program decreased by $779,756, from $2,677,937 in 2010 $1,898,180 in 2011, a 29 percent decrease.

- In the first nine months of 2011, total capacity payments to demand response resources under the PJM Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, increased by $19.5 million, or 5.4 percent, compared to the same period in 2010, from $362 Million in 2010 to $381 Million in 2011.

4 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2010 State of the Market Report for PJM*, Appendix G, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

Overview

Market Structure

- **Supply.** Average offered supply increased by 11,535, or 7.4 percent, from 156,259 MW in the third quarter of 2010 to 167,794 MW in the third quarter of 2011.[5] The large increase in offered supply was the result of the integration of the ATSI zone in the second quarter, plus the addition of 3,639 MW of nameplate capacity to PJM in 2011. This includes three large plants (over 550 MW) that have started generating in PJM since January 1, 2011. The increases in supply were partially offset by the deactivation of twelve units (738 MW) since January 1, 2011.

- **Demand.** The PJM system peak load for the third quarter of 2011 was 158,016 MW in the HE 1700 on July 21, 2011, which was 21,556 MW, or 15.8 percent, higher than the PJM peak load for the third quarter of 2010, which was 136,460 MW in the HE 1700 on July 6, 2010.[6] The ATSI transmission zone accounted for 13,953 MW in the peak hour of third quarter 2011. The peak load excluding the ATSI transmission zone was 144,063 MW, also occurring on July 21, 2011, HE 1700, an increase of 7,603 MW from the 2010 peak load.

- **Market Concentration.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping.** PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first nine months of 2011. 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 decreased from 0.2 percent in 2010 to 0.0 percent in the first nine months of 2011. In the Real-Time Energy Market offer-capped unit hours decreased from 1.2 percent in 2010 to 0.9 percent in the first nine months of 2011.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Pursuant to the January 27, 2006, FERC Order[7], PJM amended Section 6.4.2 of the PJM Operating Agreement to allow those units that were frequently mitigated over a rolling twelve-month period to include an adder in their cost-based offers. If a unit is offer capped for sixty percent or more of its run hours, but less than seventy percent, the unit is eligible for an offer cap of (i) its incremental cost plus ten percent, or (ii) its incremental cost plus $20 per megawatt-hour (Tier 1). If a unit is offer capped for seventy percent or more of its run hours, but less than eighty percent, the unit is eligible for an offer cap of (i) its incremental cost plus fifteen percent, not to exceed incremental cost plus $40 per megawatt-hour or (ii) its incremental cost plus $30 per megawatt-hour (Tier 2). If a unit is offer capped by eighty percent or more of their run hours, the unit is eligible for an offer cap of (i) its incremental cost plus ten percent; (ii) its incremental cost plus $40 per megawatt-hour; or (iii) the agreed unit-specific going forward costs of the affected unit as reflected in an agreement entered into pursuant to Schedule 1, Section 6.4.2(a)(iv) (Tier 3). This Tier qualification also applies to Associated Units, defined as any unit located at the same site with identical electrical impacts on the transmission system as a qualifying frequently mitigated unit.

  Of the 176 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first nine months of 2011, 58 (33 percent) qualified in all nine months, and 20 (11 percent) qualified in only one month of 2011. During the first nine months of 2011, there was an average of 34 units that qualified for the Tier 1 adder (compared to an average of 28 units per month since

5 Calculated values shown in Section 2, "Energy Market, Part 1," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

6 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2010 State of the Market Report for PJM*, Appendix G, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

7 114 FERC ¶ 61,076.

February, 2006), an average of 35 units qualified for the Tier 2 adder (compared to an average of 32 units per month since February, 2006), and an average of 57 units qualified for the Tier 3 adder (compared to an average of 62 units per month since February, 2006).

- **Local Market Structure.** In the first nine months of 2011, the AECO, AEP, AP, BGE, ComEd, Dominion, PECO, PENELEC, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.[8]

Market Performance: Load, Generation and Locational Marginal Price

- **Load.** PJM average real-time load in the first nine months of 2011 increased by 3.3 percent from the first nine months of 2010, from 81,068 MW to 83,762 MW. The PJM average real-time load in the first nine months of 2011 would have decreased by 1.2 percent from the first nine months of 2010, from 81,068 MW to 80,135 MW, if the ATSI transmission zone were excluded.

  PJM average day-ahead load, including DECs, in the first nine months of 2011 increased by 0.2 percent from the first nine months of 2010, from 92,683 MW to 92,828 MW. PJM average day-ahead load, including DECs, in the first nine months of 2011 would have been 3.8 percent lower than in the first nine months of 2010, from 92,683 MW to 89,146 MW if the ATSI transmission zone were excluded.

  PJM average day-ahead load, excluding virtuals, in the first nine months of 2011 increased by 6.7 percent from the first nine months of 2010, from 76,455 MW to 81,593 MW. PJM average day-ahead load, excluding virtuals, in the first nine months of 2011 would have increased by 2.0 percent from the first nine months of 2010, from 76,455 MW to 78,017 MW if the ATSI transmission zone were excluded.

  PJM average cleared DECs in the first nine months of 2011 decreased by 30.8 percent from the first nine months of 2010, from 16,228 to 11,235. PJM average Up to Congestion Transaction sink MW increased in the first nine months of 2011 by 69.2 percent from the first nine months of 2010, from 12,285.2 MW to 20,790.

- **Generation**. PJM average real-time generation in the first nine months of 2011 increased by 3.4 percent from the first nine months of 2010, from 84,086 MW to 86,963 MW. PJM average real-time generation in the first nine months of 2011 would have decreased 0.6 percent from the first nine months of 2010, from 84,086 MW to 83,573 MW if the ATSI transmission zone were excluded.

  PJM average day-ahead generation, excluding virtuals, in the first nine months of 2011 increased by 4.0 percent from the first nine months of 2010, from 84,790 MW to 88,220 MW. The PJM average day-ahead generation, excluding virtuals, in the first nine months of 2011 would have decreased by 0.1 percent from the first nine months of 2010, from 84,790 MW to 84,691 MW if the ATSI transmission zone were excluded.

  PJM average day-ahead generation, including INCs, in the first nine months of 2011 increased by 0.1 percent from the first nine months of 2010, from 95,974 MW to 96,092 MW. The PJM average day-ahead generation, including INCs, in the first nine months of 2011 would have been 3.6 percent lower than in the first nine months of 2010, from 95,974 MW to 92,501 MW if the ATSI transmission zone were excluded.

  PJM average cleared INCs in the first nine months of 2011 decreased by 29.6 percent from the first nine months of 2010, from 11,184 MW to 7,872 MW. PJM average Up to Congestion Transaction source MW increased in the first nine months of 2011 by 69.2 percent from the first nine months of 2010, from 12,285 MW to 20,790 MW.

- **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 the first nine months of 2011 compared to the first nine months of 2010. The system simple

8 See the *2010 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

average LMP was 0.7 percent lower in the first nine months of 2011 than in the first nine months of 2010, $45.79 per MWh versus $46.13 per MWh. The load-weighted average LMP was 0.9 percent lower in the first nine months of 2011 than in the first nine months of 2010, $49.48 per MWh versus $49.91 per MWh.

PJM Day-Ahead Energy Market prices decreased in the first nine months of 2011 compared to the first nine months of 2010. The system simple average LMP was 1.5 percent lower in the first nine months of 2011 than in the first nine months of 2010, $45.14 per MWh versus $45.81 per MWh. The load-weighted average LMP was 1.6 percent lower in the first nine months of 2011 than in the first nine months of 2010, $48.34 per MWh versus $49.12 per MWh. [9]

- **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 the first nine months of 2011, 10.3 percent of real-time load was supplied by bilateral contracts, 26.4 percent by spot market purchases and 63.3 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased by 1.4 percentage points; reliance on spot supply increased by 6.2 percentage points; and reliance on self-supply decreased by 4.7 percentage points in 2011. In the first nine months of 2011, 5.6 percent of day-ahead load was supplied by bilateral contracts, 24.1 percent by spot market purchases and 70.3 percent by self-supply. Compared with 2010, reliance on bilateral contracts increased by 0.8 percentage points; reliance on spot supply increased by 4.8 percentage points; and reliance on self-supply decreased by 5.6 percentage points in 2011.

Demand-Side Response

- **Demand-Side Response (DSR).** Markets require both a supply side and a demand side to function effectively. PJM wholesale market demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets.

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.

There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

- **Demand-Side Response Activity.** In the first nine months of 2011, in the Economic Program, participation decreased compared to the same period in 2010. In the first nine months of 2011, the total MWh of load reduction under the Economic Load Response Program decreased by 43,965 MWh compared to the same period in 2010, from 58,280 MWh in 2010 to 14,315 MWh in 2011, a 75 percent decrease. Total payments under the Economic Program decreased by $779,756, from $2,677,937 in 2010 $1,898,180 in 2011, a 29 percent decrease. Settled MWh and credits were lower in 2011 compared to 2010, and there were generally fewer settlements submitted, fewer registered customers, and fewer active customers compared to the same period in 2010. Participation levels since 2008 have generally been lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification. On the peak load day for the period January through September 2011 (July 21, 2011), there were 2,041.5 MW registered in the Economic Load Response Program.

That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are

9 Tables reporting zonal and jurisdictional load and prices are in Appendix A. See the *Quarterly State of the Market Report for PJM: January through September*, Appendix A.

assessed compliance on a zonal basis, is a broader issue that is being addressed through the stakeholder process.[10] More precise locational deployment of Load Management improves efficiency in a nodal market where demand side resources should be dispatched consistent with transmission constraints.

Since the implementation of the RPM design on June 1, 2007, the capacity market has become the primary source of revenue to participants in PJM demand side programs. In the first nine months of 2011, Load Management (LM) Program revenues increased by $19.5 million or 5.4 percent, from $362 million to $381 million. Through the first nine months of 2011, Synchronized Reserve credits for demand side resources increased by $2.6 million compared to the same period in 2010, from $3.7 million in 2010 to $6.2 million in 2011.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first nine months of 2011, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices in this section of the report.

Aggregate hourly supply offered increased by about 11,535 MWh in the third quarter of 2011 compared to the third quarter of 2010, while aggregate peak load increased by 21,556 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. In the Real-Time market, average load in the first nine months of 2011 increased from the same period in 2010, from 81,068 MW to 83,762 MW. 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. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first nine months of 2011 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. 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.[11]

The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2011.

10 Stakeholder committees are currently discussing rules regarding subzonal dispatch of demand resources. The Demand Response Subzonal Dispatch Task Force (DRSDTF) was established at the Markets Reliability Committee (MRC) on February 16, 2011 in response to stakeholders' request for clarity on potential future subzonal event deployments and the implications for event performance calculations. The DRSDTF was dissolved at the April 27, 2011, MRC meeting, and its responsibilities were transferred to the newly established Demand Response Subcommittee (DRS).

11 See the *2010 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

Market Structure

Supply

Figure 2-1 Average PJM day-ahead aggregate supply curves: July through September, 2010 and 2011 (See 2010 SOM, Figure 2-1)

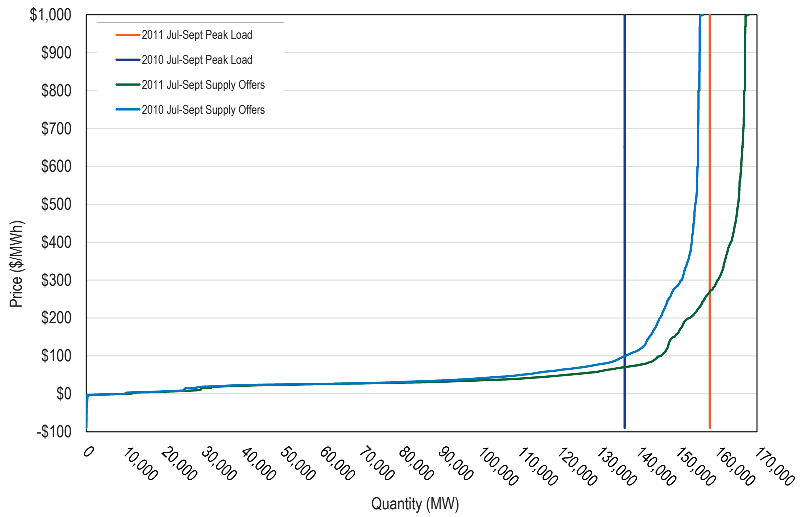


Table 2-2 Frequency distribution of day-ahead unit offer prices: July through September 2011 (See 2010 SOM, Table 2-3)

Range	All Offers
($200) - $0	10.9%
$0 - $200	51.3%
$200 - $400	22.2%
$400 - $600	10.0%
$600 - $800	3.4%
$800 - $1,000	2.1%

Demand

Table 2-3 Actual PJM footprint peak loads: July through September of 2002 to 2011 (See 2010 SOM, Table 2-4)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2002	Wed, August 14	16	63,762	NA	NA
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	Thu, July 17	17	129,481	(9,947)	(7.1%)
2009	Mon, August 10	17	126,798	(2,683)	(2.1%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011 (with ATSI)	Thu, July 21	17	158,016	21,556	15.8%
2011 (without ATSI)	Thu, July 21	17	144,063	7,603	5.6%

Figure 2-2 Actual PJM footprint peak loads: July through September of 2003 to 2011 (See 2010 SOM, Figure 2-2)

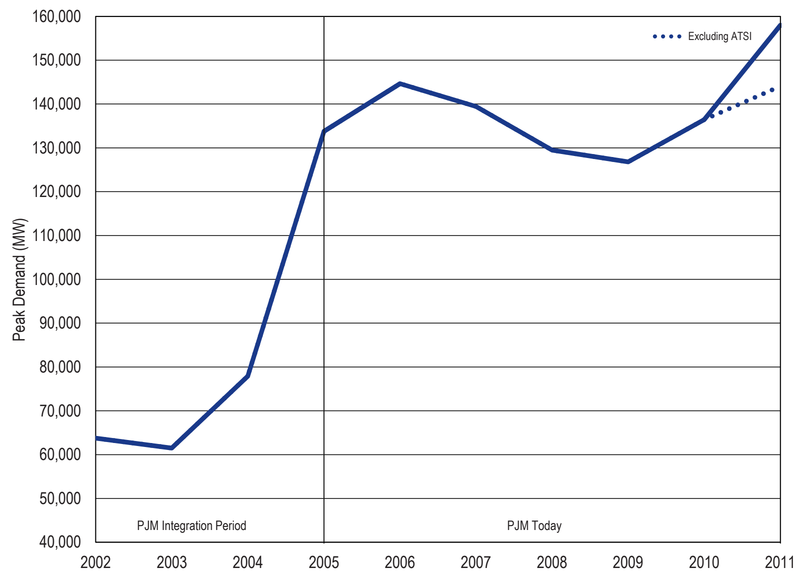
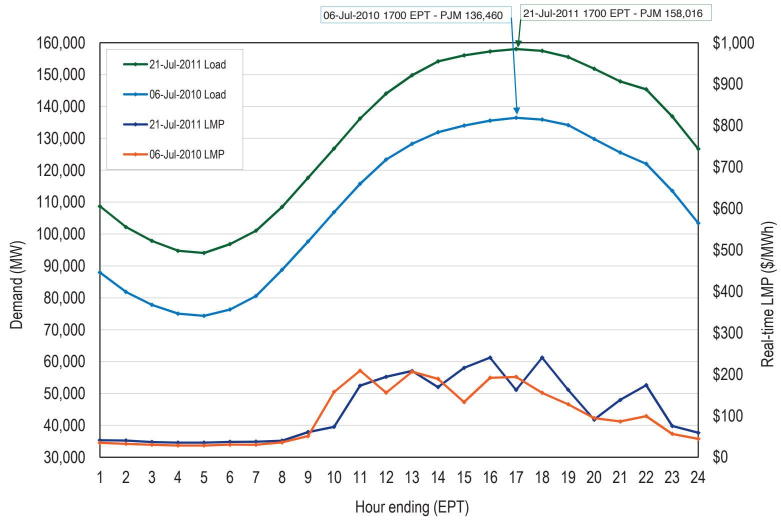


Figure 2-3 PJM third quarter peak-load comparison: Thursday, July 21, 2011, and Tuesday, July 06, 2010 (See 2010 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

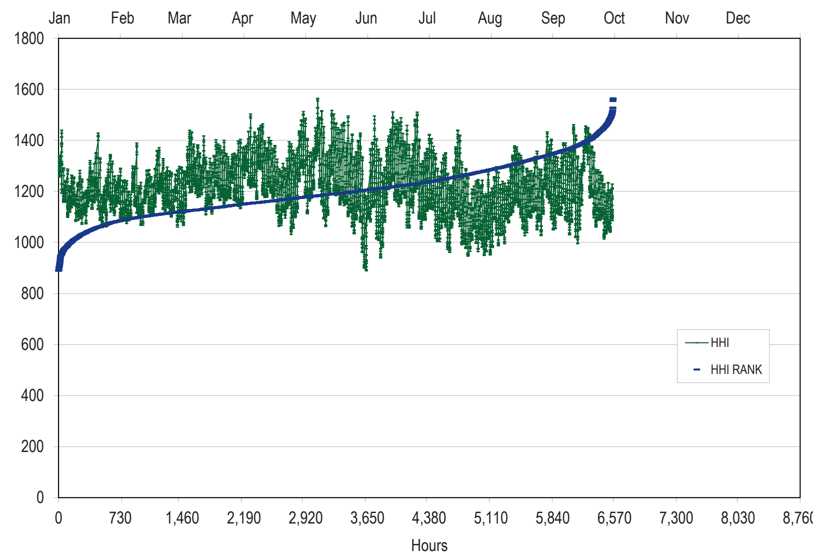
Table 2-4 PJM hourly Energy Market HHI: January through September 2011[12] (See 2010 SOM, Table 2-5)

	Hourly Market HHI
Average	1200
Minimum	889
Maximum	1564
Highest market share (One hour)	30%
Highest market share (All hours)	19%
# Hours	6,551
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Table 2-5 PJM hourly Energy Market HHI (By supply segment): January through September 2011 (See 2010 SOM, Table 2-6)

	Minimum	Average	Maximum
Base	1035	1219	1529
Intermediate	842	2801	9467
Peak	613	5720	10000

Figure 2-4 PJM hourly Energy Market HHI: January through September 2011 (See 2010 SOM, Figure 2-4)



12 This analysis includes all hours of 2011, regardless of congestion.

Local Market Structure and Offer Capping

Table 2-6 Annual offer-capping statistics: Calendar years 2006 through September 2011 (See 2010 SOM, Table 2-7)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2007	1.1%	0.2%	0.2%	0.0%
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 (Jan - Sep)	0.9%	0.3%	0.0%	0.0%

Table 2-7 Real-time offer-capped unit statistics: January through September 2011 (See 2010 SOM, Table 2-8)

	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	4	9	5
80% and < 90%	0	0	1	1	4	9
75% and < 80%	0	0	0	0	3	3
70% and < 75%	0	0	0	0	2	6
60% and < 70%	0	1	0	1	1	23
50% and < 60%	0	0	0	1	10	24
25% and < 50%	1	0	0	3	14	77
10% and < 25%	5	1	1	1	1	51

Local Market Structure

Table 2-8 Three pivotal supplier results summary for regional constraints: January through September 2011 (See 2010 SOM, Table 2-9)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	6,653	1,071	16%	6,205	93%
	Off Peak	3,657	491	13%	3,442	94%
AEP-DOM	Peak	1,804	27	1%	1,797	100%
	Off Peak	2,113	47	2%	2,099	99%
AP South	Peak	16,791	347	2%	16,688	99%
	Off Peak	12,230	346	3%	12,116	99%
Bedington - Black Oak	Peak	41	0	0%	41	100%
	Off Peak	9	1	11%	8	89%
Dominion East	Peak	1,479	12	1%	1,469	99%
	Off Peak	578	8	1%	575	99%
East	Peak	726	221	30%	636	88%
	Off Peak	155	63	41%	118	76%
West	Peak	211	93	44%	158	75%
	Off Peak	21	10	48%	16	76%

Table 2-9 Three pivotal supplier test details for regional constraints: January through September 2011 (See 2010 SOM, Table 2-10)

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	316	373	15	2	13
	Off Peak	369	385	14	2	12
AEP-DOM	Peak	276	308	8	0	8
	Off Peak	350	423	8	0	8
AP South	Peak	392	449	8	0	8
	Off Peak	486	524	9	0	8
Bedington - Black Oak	Peak	70	75	8	0	8
	Off Peak	19	40	9	1	8
Dominion East	Peak	115	167	1	0	1
	Off Peak	80	148	2	0	2
East	Peak	637	898	16	5	11
	Off Peak	327	531	12	5	7
West	Peak	434	614	14	6	8
	Off Peak	218	423	13	5	8

Table 2-10 Summary of three pivotal supplier tests applied to uncommitted units for regional constraints: January through September 2011 (See 2010 SOM, Table 2-11)

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	6,653	396	6%	190	3%	48%
	Off Peak	3,657	182	5%	69	2%	38%
AEP-DOM	Peak	1,804	37	2%	14	1%	38%
	Off Peak	2,113	45	2%	24	1%	53%
AP South	Peak	16,791	206	1%	55	0%	27%
	Off Peak	12,230	208	2%	44	0%	21%
Bedington - Black Oak	Peak	41	0	0%	0	0%	0%
	Off Peak	9	0	0%	0	0%	0%
Dominion East	Peak	1,479	4	0%	0	0%	0%
	Off Peak	578	0	0%	0	0%	0%
East	Peak	726	12	2%	3	0%	25%
	Off Peak	155	1	1%	0	0%	0%
West	Peak	211	17	8%	7	3%	41%
	Off Peak	21	1	5%	0	0%	0%

Frequently Mitigated Unit and Associated Unit Adders

Table 2-11 Frequently mitigated units and associated units (By month): January through September 2011 (See 2010 SOM, Table 2-26)

Month	Tier 1	Tier 2	Tier 3	Total Units Eligible For FMU/AU Adder
Jan	46	22	66	134
Feb	34	43	60	137
Mar	30	46	66	142
Apr	34	45	62	141
May	37	48	59	144
Jun	31	50	61	142
Jul	45	32	43	120
Aug	33	14	44	91
Sep	18	19	55	92

Figure 2-5 Frequently mitigated units and associated units (By month): February, 2006 through September, 2011 (New Figure)

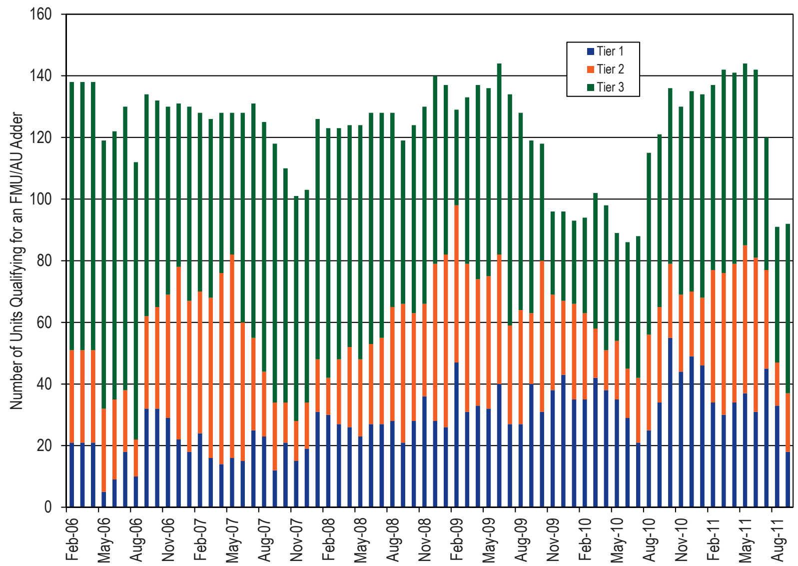


Figure 2-6 Frequently mitigated units and associated units total months eligible: February, 2006 through September, 2011 (New Figure)

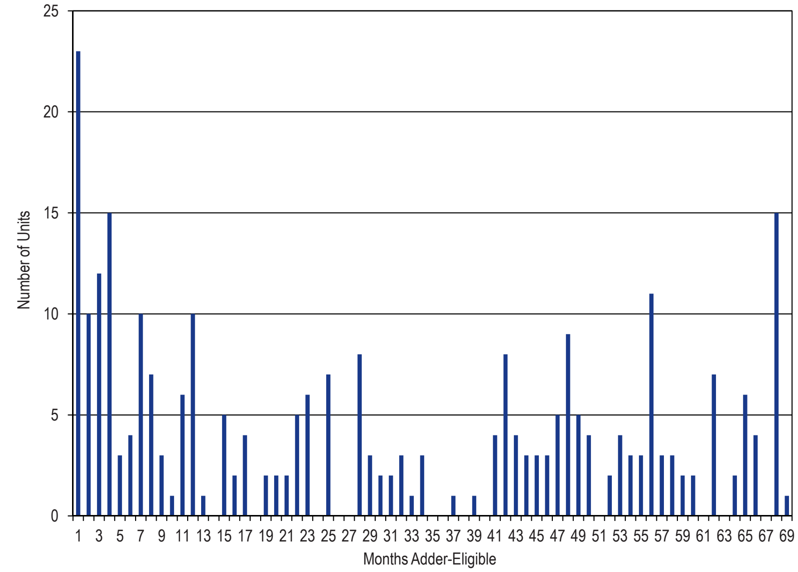


Table 2-12 Frequently mitigated units and associated units total months eligible: January through September 2011 (See 2010 SOM, Table 2-27)

Months Adder-Eligible	FMU & AU Count
1	20
2	5
3	7
4	2
5	8
6	30
7	26
8	20
9	58
Total	176

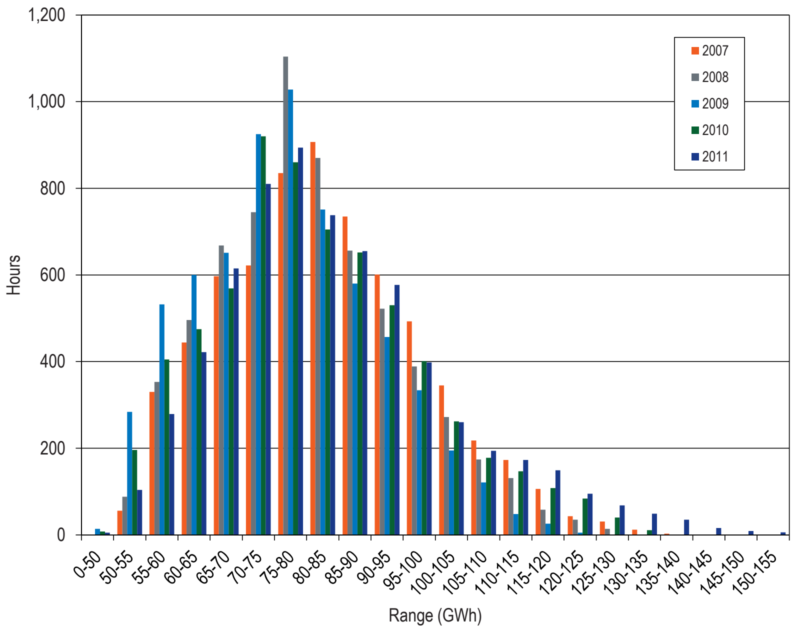
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 PJM real-time accounting load histogram: January through September 2007 through 2011 (New Figure)[13]



PJM Real-Time, Average Load

Table 2-13 PJM real-time average hourly load: January through September 1998 through 2011 (See 2010 SOM, Table 2-28)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
Jan - Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	29,112	28,876	5,780	NA	NA	NA
1999	30,236	29,545	6,306	3.9%	2.3%	9.1%
2000	30,266	30,140	5,764	0.1%	2.0%	(8.6%)
2001	31,060	30,732	6,156	2.6%	2.0%	6.8%
2002	35,652	33,985	8,734	14.8%	10.6%	41.9%
2003	37,996	37,357	7,187	6.6%	9.9%	(17.7%)
2004	45,294	43,254	10,512	19.2%	15.8%	46.3%
2005	78,235	75,111	17,541	72.7%	73.7%	66.9%
2006	80,717	78,814	15,568	3.2%	4.9%	(11.2%)
2007	83,114	82,026	15,386	3.0%	4.1%	(1.2%)
2008	80,611	79,204	14,389	(3.0%)	(3.4%)	(6.5%)
2009	76,956	76,355	13,879	(4.5%)	(3.6%)	(3.5%)
2010	81,068	79,053	16,209	5.3%	3.5%	16.8%
2011	83,762	81,027	17,604	3.3%	2.5%	8.6%

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

PJM Real-Time, Monthly Average Load

Figure 2-8 PJM real-time average hourly load: Calendar years 2010 through September 2011 (See 2010 SOM, Figure 2-6)

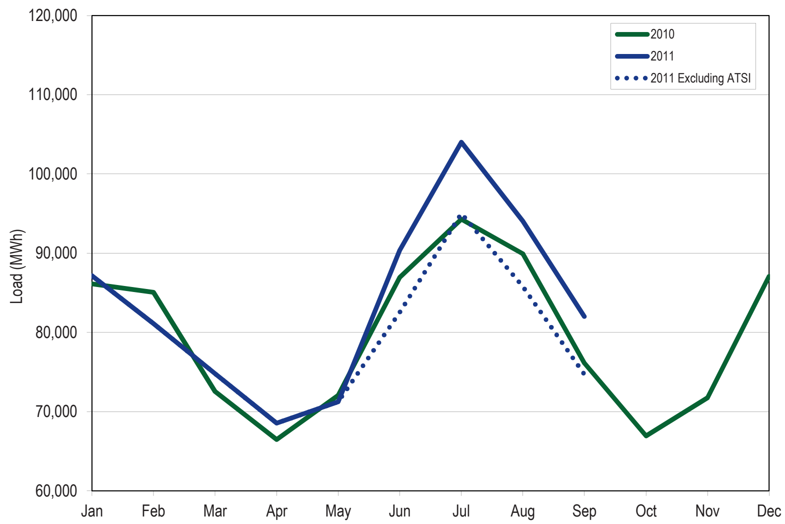


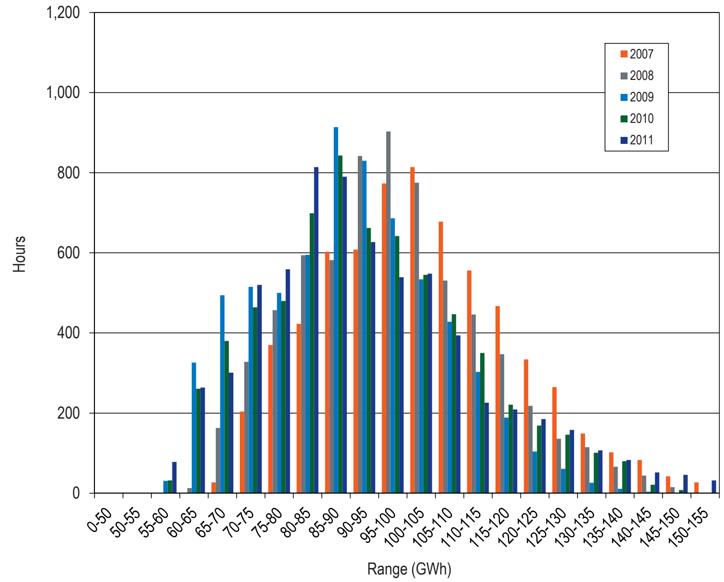
Table 2-14 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through September 2011 (See 2010 SOM, Table 2-30)

	Summer THI	Winter WWP	Shoulder Average Temperature
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	77.36	24.28	57.22
2011	76.68	25.20	57.21

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-9 PJM day-ahead accounting load histogram: January through September 2007 through 2011 (New Figure)



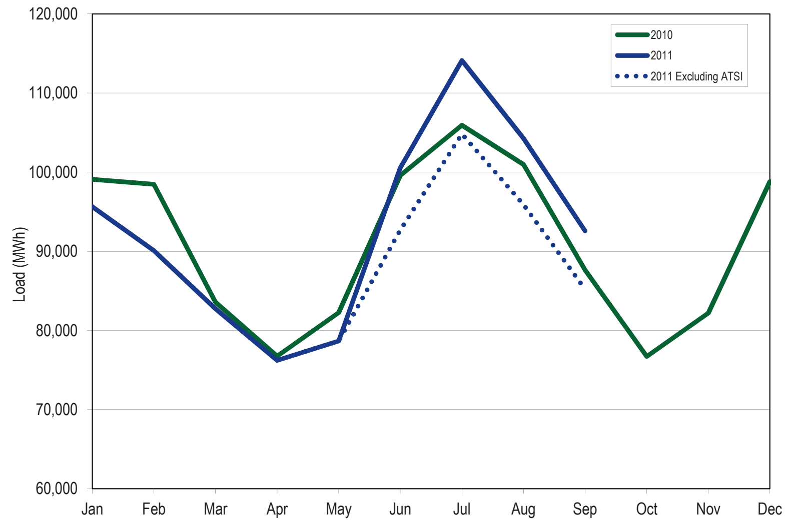
PJM Day-Ahead, Average Load

Table 2-15 PJM day-ahead average load: January through September 2000 through 2011 (See 2010 SOM, Table 2-31)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
Jan - Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	34,064	34,690	7,649	NA	NA	NA
2001	33,898	32,931	6,929	(0.5%)	(5.1%)	(9.4%)
2002	41,547	39,129	11,053	22.6%	18.8%	59.5%
2003	45,373	45,077	9,045	9.2%	15.2%	(18.2%)
2004	54,997	52,044	13,103	21.2%	15.5%	44.9%
2005	92,162	89,314	18,867	67.6%	71.6%	44.0%
2006	95,572	92,943	17,415	3.7%	4.1%	(7.7%)
2007	102,742	101,669	17,075	7.5%	9.4%	(1.9%)
2008	97,506	96,480	16,051	(5.1%)	(5.1%)	(6.0%)
2009	89,680	89,515	15,756	(8.0%)	(7.2%)	(1.8%)
2010	92,683	90,804	17,769	3.3%	1.4%	12.8%
2011	92,828	89,671	19,456	0.2%	(1.2%)	9.5%

PJM Day-Ahead, Monthly Average Load

Figure 2-10 PJM day-ahead average load: Calendar years 2010 through September 2011 (See 2010 SOM, Figure 2-8)



Real-Time and Day-Ahead Load

Table 2-16 Cleared day-ahead and real-time load (MWh): January through September 2010 and 2011 (See 2010 SOM, Table 2-32)

		Day Ahead				Real Time	Average Difference	
	Year	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bid
Average	2010	75,201	1,254	16,228	92,683	81,068	11,615	(4,613)
	2011	80,729	864	11,235	92,828	83,762	9,066	(2,169)
Median	2010	73,142	1,152	16,160	90,804	79,053	11,750	(4,410)
	2011	77,364	859	10,959	89,671	81,027	8,644	(2,316)
Standard deviation	2010	15,205	483	2,660	17,769	16,209	1,561	(1,100)
	2011	17,424	192	2,578	19,456	17,604	1,852	(726)
Peak average	2010	83,907	1,461	17,674	103,042	90,034	13,008	(4,666)
	2011	89,882	941	13,011	103,833	93,020	10,813	(2,198)
Peak median	2010	82,003	1,353	17,596	100,746	87,848	12,898	(4,698)
	2011	86,816	945	12,751	100,962	89,953	11,010	(1,742)
Peak standard deviation	2010	13,306	475	2,159	15,131	14,347	784	(1,375)
	2011	16,471	189	2,135	17,711	16,475	1,236	(899)
Off peak average	2010	67,588	1,073	14,964	83,625	73,227	10,397	(4,566)
	2011	72,646	795	9,668	83,110	75,586	7,523	(2,145)
Off peak median	2010	65,914	985	14,768	81,899	71,612	10,286	(4,482)
	2011	70,493	793	9,418	80,730	72,998	7,732	(1,686)
Off peak standard deviation	2010	12,422	412	2,401	14,689	13,443	1,246	(1,154)
	2011	13,887	168	1,803	15,313	14,191	1,121	(682)

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): January through September 2011 (See 2010 SOM, Figure 2-9)

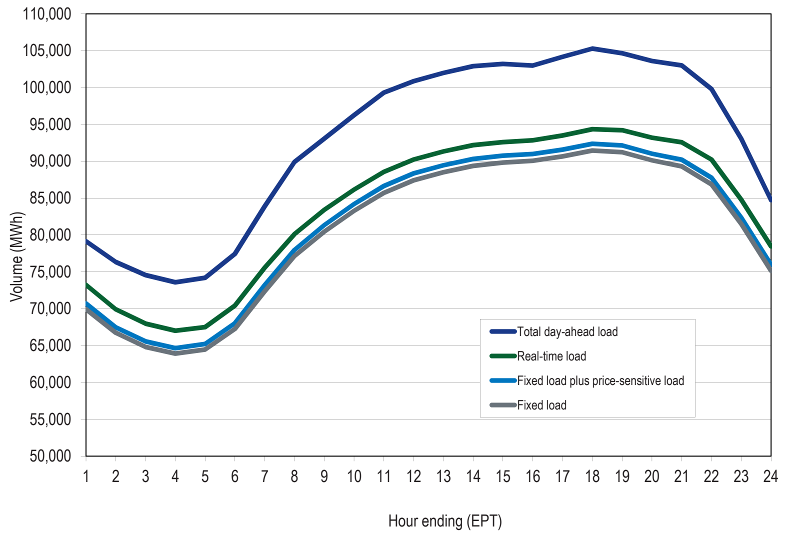
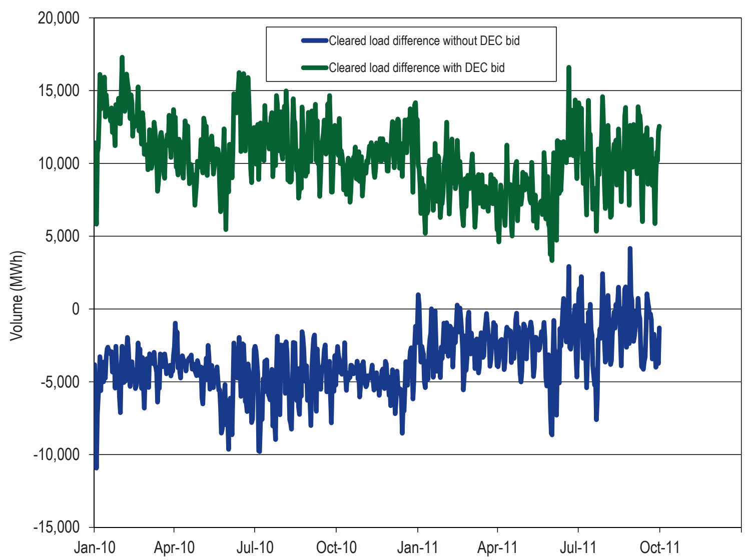


Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): January 2010 through September 2011 (See 2010 SOM, Figure 2-10)



Real-Time and Day-Ahead Generation

Table 2-17 Day-ahead and real-time generation (MWh): January through September 2010 and 2011 (See 2010 SOM, Table 2-33)

		Day Ahead			Real Time	Average Difference	
	Year	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	2010	84,790	11,184	95,974	84,086	704	11,888
	2011	88,220	7,872	96,092	86,963	1,257	9,129
Median	2010	83,148	11,070	94,108	82,213	935	11,895
	2011	85,314	7,800	93,014	84,261	1,052	8,753
Standard deviation	2010	17,552	1,585	18,153	16,346	1,207	1,807
	2011	18,881	1,388	19,705	17,370	1,511	2,335
Peak average	2010	94,505	11,996	106,501	92,894	1,611	13,607
	2011	98,419	8,823	107,243	95,885	2,534	11,357
Peak median	2010	92,176	11,916	104,166	90,717	1,459	13,449
	2011	95,642	8,690	104,288	92,952	2,690	11,336
Peak standard deviation	2010	15,011	1,449	15,467	14,464	547	1,002
	2011	17,199	1,133	17,864	16,250	949	1,614
Off peak average	2010	76,295	10,474	86,769	76,383	(89)	10,386
	2011	79,214	7,031	86,246	79,084	130	7,162
Off peak median	2010	74,777	10,458	85,031	74,983	(205)	10,048
	2011	76,818	6,864	83,897	76,681	137	7,216
Off peak standard deviation	2010	15,026	1,338	15,063	13,810	1,216	1,252
	2011	15,400	994	15,579	14,235	1,165	1,343

Figure 2-13 Day-ahead and real-time generation (Average hourly volumes): January through September 2011 (See 2010 SOM, Figure 2-11)

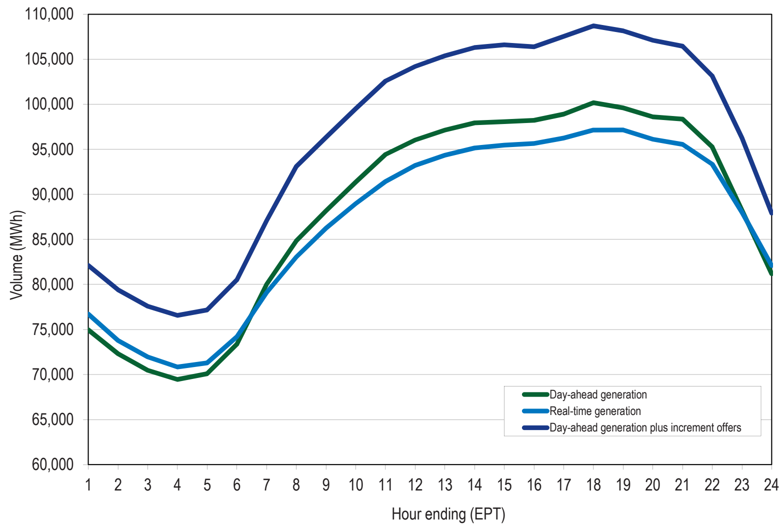
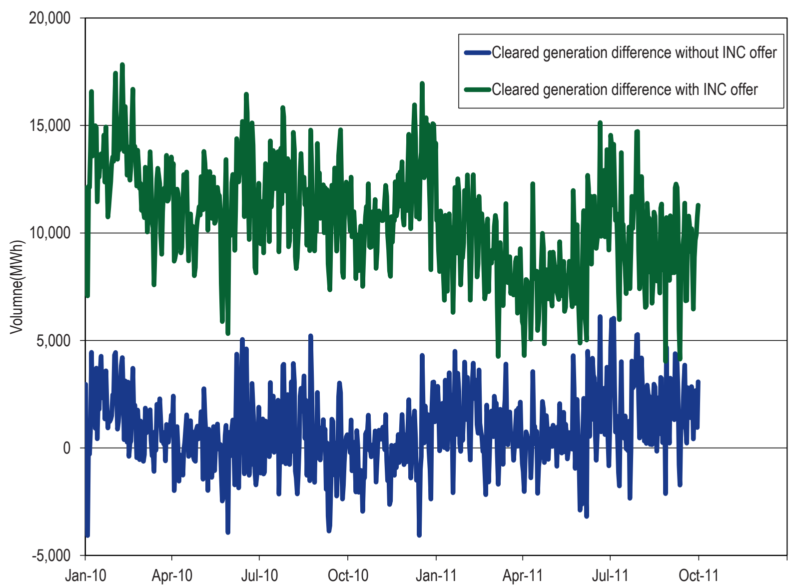


Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January 2010 through September 2011 (See 2010 SOM, Figure 2-12)



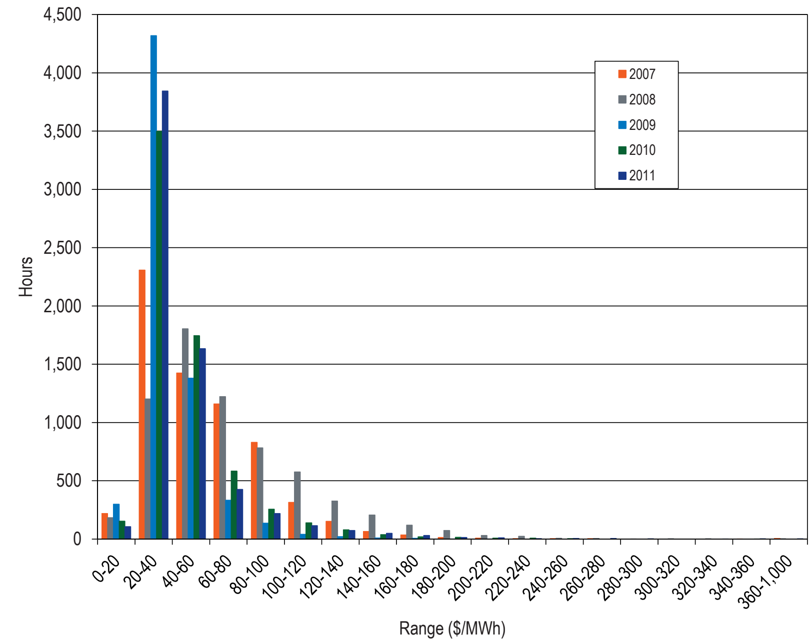
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-15 Price histogram for the PJM Real-Time Energy Market: January through September 2007 through 2011 (New Figure)



PJM Real-Time, Average LMP

Table 2-18 PJM real-time, simple average LMP (Dollars per MWh): January through September 1998 through 2011 (See 2010 SOM, Table 2-34)

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

Real-Time, Load-Weighted, Average LMP

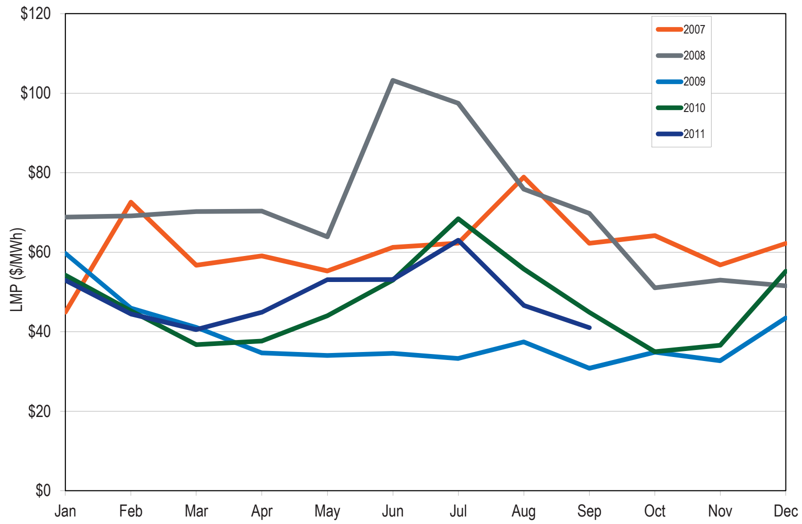
PJM Real-Time, Load-Weighted, Average LMP

Table 2-19 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through September 1998 through 2011 (See 2010 SOM, Table 2-38)

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

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

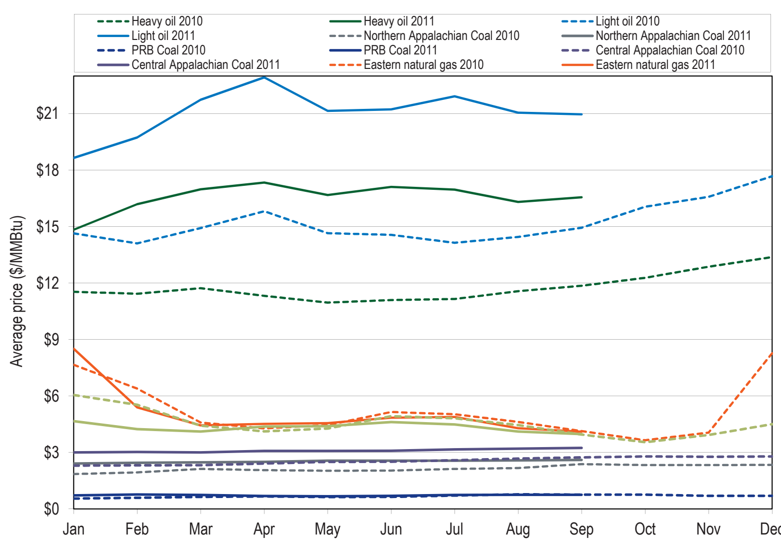
Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through September 2011 (See 2010 SOM, Figure 2-14)



Real-Time, Fuel-Cost-Adjusted, Load-Weighted LMP

Fuel Cost

Figure 2-17 Spot average fuel price comparison: Calendar years 2010 through September 2011 (See 2010 SOM, Table 2-15)

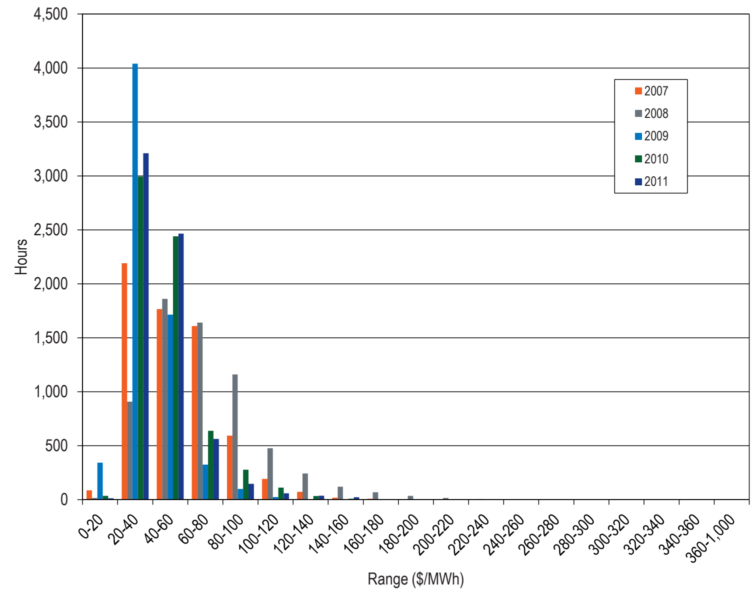


Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-18 Price histogram for the PJM Day-Ahead Energy Market: January through September 2007 through 2011 (New Figure)



PJM Day-Ahead, Average LMP

Table 2-20 PJM day-ahead, simple average LMP (Dollars per MWh): January through September 2000 through 2011 (See 2010 SOM, Table 2-43)

	Day-Ahead LMP			Year-to-Year Change		
Jan - Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$28.19	$21.10	$19.10	NA	NA	NA
2001	$36.07	$30.02	$34.25	28.0%	42.3%	79.4%
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%

Day-Ahead, Load-Weighted, Average LMP

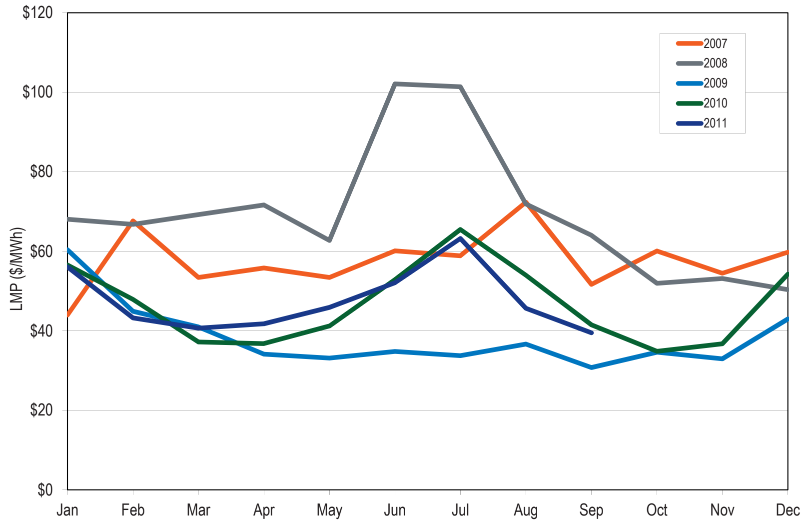
PJM Day-Ahead, Load-Weighted, Average LMP

Table 2-21 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September 2000 through 2011 (See 2010 SOM, Table 2-46)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Jan - Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.81	$24.99	$20.40	NA	NA	NA
2001	$39.88	$32.68	$42.01	25.3%	30.8%	106.0%
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%

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

Figure 2-19 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2007 through September 2011 (See 2010 SOM, Table 2-17)



Virtual Offers and Bids

Table 2-22 Monthly volume of cleared and submitted INCs, DECs: January 2010 through September 2011 (See 2010 SOM, Table 2-61)

		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
2010	Jan	11,144	21,634	282	936	17,513	29,406	266	893
2010	Feb	12,387	23,827	387	1,122	17,602	28,542	270	883
2010	Mar	10,811	21,062	308	915	15,019	24,968	253	763
2010	Apr	10,512	19,940	289	784	13,875	24,458	246	705
2010	May	11,165	19,744	218	806	15,556	25,194	223	787
2010	Jun	11,534	22,956	254	1,496	17,689	27,422	258	1,246
2010	Jul	11,276	23,414	250	1,585	17,223	25,690	304	1,284
2010	Aug	10,567	20,751	226	1,332	15,656	21,745	327	1,140
2010	Sep	10,944	21,365	263	1,232	15,522	22,646	311	1,072
2010	Oct	10,454	20,253	234	1,129	14,011	22,154	253	1,030
2010	Nov	11,134	17,495	220	1,035	15,315	22,618	271	1,055
2010	Dec	12,656	20,957	277	1,340	16,560	26,995	274	1,266
2010	Annual	11,208	21,101	267	1,143	15,952	25,135	271	1,011
2011	Jan	8,137	14,299	218	1,077	11,135	17,917	224	963
2011	Feb	8,532	16,263	215	1,672	11,076	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	Annual	7,794	13,199	188	1,059	11,122	16,718	213	919

Table 2-23 Daily average of cleared and submitted up-to congestion bids by month: January 2010 through September 2011 (New Table)

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2010	Jan	5,647	9,549	114	189
2010	Feb	7,961	12,047	150	244
2010	Mar	8,796	12,916	149	234
2010	Apr	9,004	13,398	137	215
2010	May	7,430	12,114	131	208
2010	Jun	20,537	27,576	168	266
2010	Jul	30,176	40,006	202	336
2010	Aug	10,902	21,354	150	287
2010	Sep	10,114	21,777	156	488
2010	Oct	12,044	25,544	195	473
2010	Nov	14,380	29,788	261	602
2010	Dec	17,928	42,414	319	724
2010	Annual	12,910	22,374	178	355
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	Annual	20,790	48,602	515	1,105

Figure 2-20 Monthly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) January, 2005 through September, 2011 (New Figure)

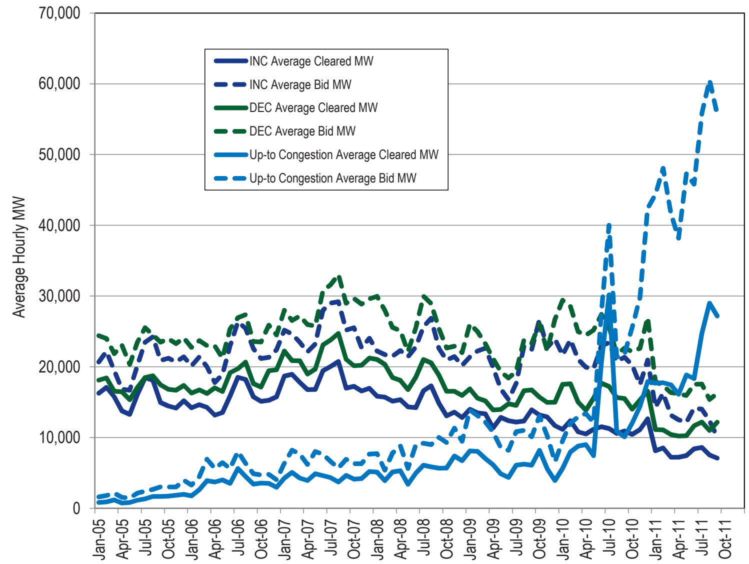


Table 2-24 PJM INC and DEC bids by type of parent organization (MW): January through September 2011 (See 2010 SOM, Table 2-63)

	2010 (Jan - Sep)		2011 (Jan - Sep)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	132,521,659	42.9%	89,825,701	45.8%
Physical	176,354,389	57.1%	106,161,386	54.2%
Total	308,876,049	100.0%	195,987,087	100.0%

Table 2-25 PJM virtual offers and bids by top ten aggregates (MW): January through September 2010 and 2011 (See 2010 SOM, Table 2-64)

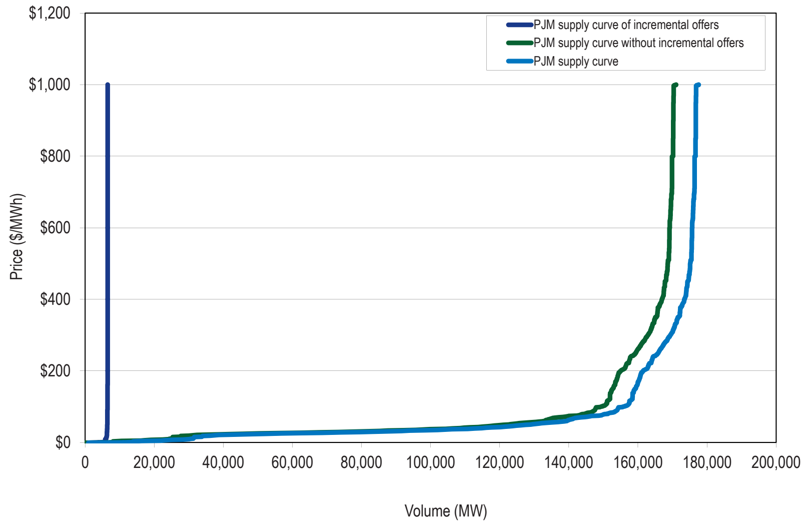
2010 (Jan - Sep)					2011 (Jan - Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	45,935,725	52,987,976	98,923,702	WESTERN HUB	HUB	21,803,278	25,055,528	46,858,806
N ILLINOIS HUB	HUB	8,130,610	8,302,430	16,433,040	N ILLINOIS HUB	HUB	7,548,766	11,359,168	18,907,933
AEP-DAYTON HUB	HUB	4,500,957	5,745,609	10,246,566	AEP-DAYTON HUB	HUB	4,595,058	6,186,285	10,781,343
PSEG	ZONE	2,099,900	4,656,424	6,756,324	MISO	INTERFACE	189,307	5,304,896	5,494,202
PPL	ZONE	395,988	6,247,001	6,642,988	PECO	ZONE	1,322,244	3,821,502	5,143,746
Pepco	ZONE	5,157,391	1,000,756	6,158,147	SOUTHIMP	INTERFACE	4,480,640	0	4,480,640
BGE	ZONE	3,175,589	2,702,532	5,878,121	PPL	ZONE	201,981	3,028,982	3,230,963
JCPL	ZONE	3,412,010	2,038,140	5,450,150	ComEd	ZONE	1,965,887	216,118	2,182,004
MISO	INTERFACE	1,040,035	2,811,361	3,851,396	GEN BUS	GEN	1,037,760	1,037,827	2,075,587
ComEd	ZONE	1,607,186	1,460,892	3,068,078	BGE	ZONE	89,509	1,680,790	1,770,299
Top ten total		75,455,392	87,953,121	163,408,513			43,234,428	57,691,095	100,925,523
PJM total		141,572,307	167,303,742	308,876,049			86,469,663	109,517,424	195,987,087
Top ten total as percent of PJM total		53.3%	52.6%	52.9%			50.0%	52.7%	51.5%

Table 2-26 PJM cleared up-to congestion import, export and wheel bids by top ten source and sink pairs (MW): January through September 2010 and 2011 (New Table)

2010 (Jan-Sep)														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	COMED	ZONE	3,356,063	COMED	ZONE	MISO	INTERFACE	3,215,737	SOUTHIMP	INTERFACE	SOUTHEXP	INTERFACE	3,014,673
MISO	INTERFACE	DAY	ZONE	3,129,246	DAY	ZONE	MISO	INTERFACE	2,760,350	NCMPAIMP	INTERFACE	NCMPAEXP	INTERFACE	2,129,852
MISO	INTERFACE	COOK	EHVAGG	2,822,921	BEAV DUQ UNIT1	AGGREGATE	MICHFE	INTERFACE	2,034,993	NORTHWEST	INTERFACE	NIPSCO	INTERFACE	733,295
MISO	INTERFACE	AEP-DAYTON HUB	HUB	2,016,767	ROCKPORT	EHVAGG	MISO	INTERFACE	1,834,850	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	452,614
NYIS	INTERFACE	PSEG	ZONE	1,622,726	COOK	EHVAGG	MISO	INTERFACE	1,330,241	MISO	INTERFACE	OVEC	INTERFACE	203,546
MISO	INTERFACE	112 WILTON	EHVAGG	1,295,242	MT STORM	EHVAGG	MISO	INTERFACE	1,076,845	NORTHWEST	INTERFACE	MISO	INTERFACE	122,821
MISO	INTERFACE	GREENLAND GAP	EHVAGG	940,603	21 KINCA ATR24304	AGGREGATE	MISO	INTERFACE	816,791	OVEC	INTERFACE	MISO	INTERFACE	118,125
MISO	INTERFACE	ROCKPORT	EHVAGG	761,371	21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	565,514	NORTHWEST	INTERFACE	IMO	INTERFACE	116,579
NYIS	INTERFACE	MARION	AGGREGATE	634,715	WESTERN HUB	HUB	IMO	INTERFACE	534,406	SOUTHEAST	AGGREGATE	CPLEEXP	INTERFACE	113,000
MISO	INTERFACE	YUKON	EHVAGG	596,074	23 COLLINS	EHVAGG	MISO	INTERFACE	500,479	OVEC	INTERFACE	SOUTHEXP	INTERFACE	92,505
Top ten total				17,175,726					14,670,206					7,097,010
PJM total				55,024,722					49,156,193					9,210,022
Top ten total as percent of PJM total				31.2%					29.8%					77.1%

2011 (Jan-Sep)														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,697,394	LUMBERTON	AGGREGATE	SOUTHEAST	AGGREGATE	5,458,432	CPLEIMP	INTERFACE	NCMPAEXP	INTERFACE	397,775
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	1,950,476	WESTERN HUB	HUB	MISO	INTERFACE	2,629,676	CPLEIMP	INTERFACE	DUKEXP	INTERFACE	287,643
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	1,686,827	FE GEN	AGGREGATE	SOUTHWEST	AGGREGATE	1,286,402	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	204,835
MISO	INTERFACE	112 WILTON	EHVAGG	1,584,297	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,269,001	NORTHWEST	INTERFACE	MISO	INTERFACE	188,239
NYIS	INTERFACE	MARION	AGGREGATE	1,137,814	23 COLLINS	EHVAGG	MISO	INTERFACE	1,149,885	NYIS	INTERFACE	MICHFE	INTERFACE	115,574
NYIS	INTERFACE	PSEG	ZONE	966,283	21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	1,074,975	SOUTHWEST	AGGREGATE	OVEC	INTERFACE	111,932
SOUTHEAST	AGGREGATE	CRVWOOD	AGGREGATE	855,719	BELMONT	EHVAGG	OVEC	INTERFACE	934,962	MISO	INTERFACE	NIPSCO	INTERFACE	93,485
OVEC	INTERFACE	MARYSVILLE	EHVAGG	813,663	FOWLER 34.5 KV FWLR1AWF	AGGREGATE	OVEC	INTERFACE	783,782	NIPSCO	INTERFACE	OVEC	INTERFACE	71,840
OVEC	INTERFACE	JEFFERSON	EHVAGG	800,642	RECO	ZONE	IMO	INTERFACE	776,982	NIPSCO	INTERFACE	MISO	INTERFACE	63,809
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	798,145	BEAV DUQ UNIT1	AGGREGATE	MICHFE	INTERFACE	742,722	NCMPAIMP	INTERFACE	OVEC	INTERFACE	62,459
Top ten total				13,291,259					16,106,818					1,597,590
PJM total				75,607,294					58,031,610					2,813,116
Top ten total as percent of PJM total				17.6%					27.8%					56.8%

Figure 2-21 PJM day-ahead aggregate supply curves: 2011 example day (See 2010 SOM, Figure 2-18)



Price Convergence

Table 2-27 Day-ahead and real-time simple average LMP (Dollars per MWh): January through September 2010 and 2011 (See 2010 SOM, Table 2-65)

	2010 (Jan - Sep)				2011 (Jan - Sep)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$45.81	$46.13	$0.32	0.7%	$45.14	$45.79	$0.65	1.4%
Median	$41.03	$37.89	($3.14)	(8.3%)	$40.20	$37.05	($3.14)	(8.5%)
Standard deviation	$19.59	$26.99	$7.39	27.4%	$22.68	$32.25	$9.57	29.7%
Peak average	$54.53	$55.33	$0.79	1.4%	$54.11	$55.31	$1.19	2.2%
Peak median	$47.51	$45.26	($2.25)	(5.0%)	$47.56	$42.89	($4.67)	(10.9%)
Peak standard deviation	$20.60	$29.57	$8.97	30.3%	$27.09	$40.01	$12.92	32.3%
Off peak average	$38.18	$38.08	($0.10)	(0.3%)	$37.22	$37.40	$0.18	0.5%
Off peak median	$34.39	$32.45	($1.94)	(6.0%)	$33.74	$32.90	($0.84)	(2.6%)
Off peak standard deviation	$14.97	$21.50	$6.54	30.4%	$13.67	$19.86	$6.19	31.2%

Table 2-28 Day-ahead and real-time simple average LMP (Dollars per MWh): January through September 2000 through 2011 (See 2010 SOM, Table 2-66)

Jan - Sep	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$28.19	$26.95	($1.24)	(4.4%)
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%

Table 2-29 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through September 2007 through 2011 (See 2010 SOM, Table 2-67)

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%

Figure 2-22 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through September 2011 (See 2010 SOM, Figure 2-19)

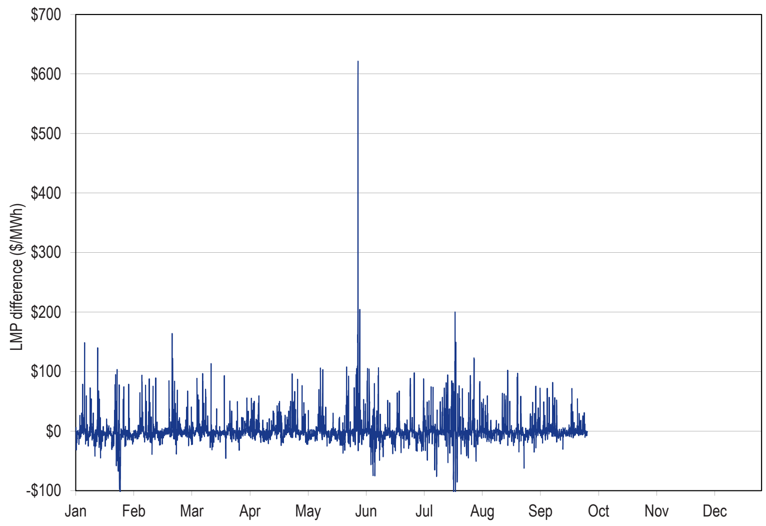


Figure 2-23 Monthly simple average of real-time minus day-ahead LMP: January through September 2011 (See 2010 SOM, Figure 2-20)

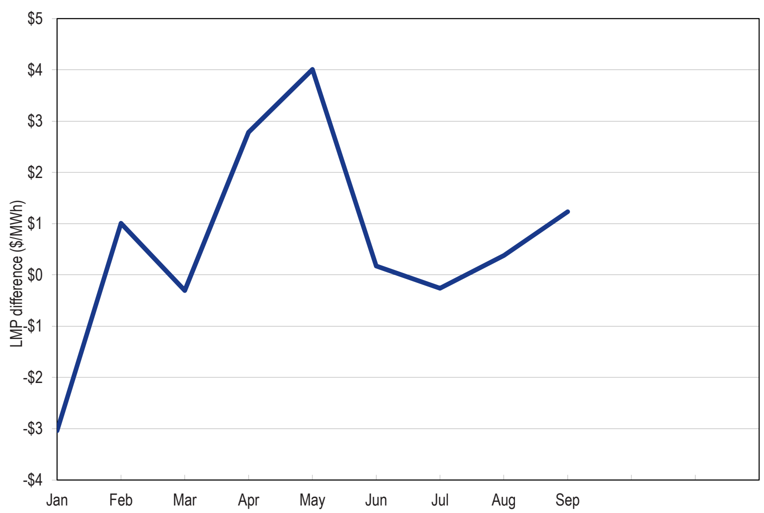
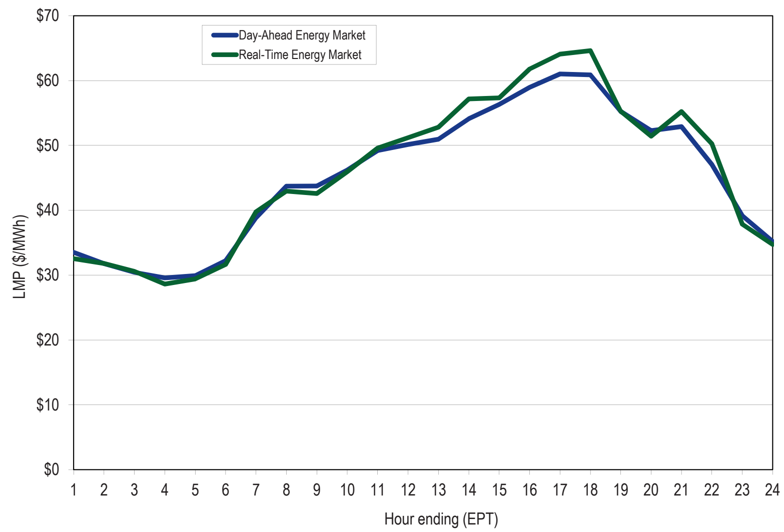


Figure 2-24 PJM system simple hourly average LMP: January through September 2011 (See 2010 SOM, Figure 2-21)



Load and Spot Market

Real-Time Load and Spot Market

Table 2-30 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2010 through September 2011 (See 2010 SOM, Table 2-70)

	2010			2011			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.0%	17.4%	70.5%	9.3%	28.8%	61.9%	(2.7%)	11.4%	(8.6%)
Feb	13.5%	18.1%	68.4%	10.9%	27.9%	61.2%	(2.6%)	9.8%	(7.2%)
Mar	12.8%	18.2%	68.9%	10.4%	29.3%	60.3%	(2.5%)	11.1%	(8.6%)
Apr	12.6%	19.3%	68.1%	10.7%	25.3%	64.1%	(1.9%)	6.0%	(4.1%)
May	11.6%	19.9%	68.5%	11.1%	25.7%	63.3%	(0.4%)	5.8%	(5.2%)
Jun	10.4%	19.0%	70.5%	10.5%	25.4%	64.1%	0.1%	6.4%	(6.5%)
Jul	9.8%	19.5%	70.7%	9.5%	24.7%	65.8%	(0.3%)	5.2%	(4.9%)
Aug	10.6%	20.5%	68.9%	10.3%	24.6%	65.1%	(0.3%)	4.1%	(3.8%)
Sep	12.0%	22.3%	65.7%	10.9%	26.7%	62.4%	(1.1%)	4.4%	(3.3%)
Oct	13.0%	25.1%	61.9%						
Nov	12.8%	22.7%	64.5%						
Dec	11.5%	21.8%	66.7%						
Annual	11.8%	20.2%	68.0%	10.3%	26.4%	63.3%	(1.4%)	6.2%	(4.7%)

Day-Ahead Load and Spot Market

Table 2-31 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2010 through September 2011 (See 2010 SOM, Table 2-71)

	2010			2011			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.6%	17.8%	77.6%	4.7%	23.7%	71.6%	0.1%	5.9%	(6.0%)
Feb	4.6%	18.4%	77.0%	5.4%	23.7%	70.9%	0.8%	5.3%	(6.1%)
Mar	4.8%	18.4%	76.8%	5.8%	24.3%	70.0%	1.0%	5.8%	(6.8%)
Apr	4.9%	19.1%	76.0%	6.1%	23.8%	70.1%	1.2%	4.7%	(5.9%)
May	6.6%	19.0%	74.4%	6.0%	24.0%	70.0%	(0.6%)	5.1%	(4.5%)
Jun	4.6%	18.6%	76.7%	6.0%	25.3%	68.8%	1.3%	6.6%	(7.9%)
Jul	4.7%	18.6%	76.6%	5.5%	23.4%	71.2%	0.7%	4.7%	(5.5%)
Aug	4.8%	19.3%	75.9%	5.7%	24.1%	70.1%	1.0%	4.8%	(5.8%)
Sep	4.6%	20.7%	74.8%	5.8%	25.2%	69.0%	1.2%	4.5%	(5.8%)
Oct	4.9%	22.7%	72.4%						
Nov	4.9%	20.7%	74.4%						
Dec	4.6%	19.2%	76.2%						
Annual	4.9%	19.3%	75.8%	5.6%	24.1%	70.3%	0.8%	4.8%	(5.6%)

Marginal Losses

Table 2-32 PJM real-time, simple average LMP components (Dollars per MWh): January through September 2008 to 2011 (See 2010 SOM, Table 2-50)[14]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008 (Jan - Sep)	$71.95	$71.85	$0.06	$0.05
2009 (Jan - Sep)	$37.42	$37.35	$0.05	$0.03
2010 (Jan - Sep)	$46.13	$46.03	$0.06	$0.04
2011 (Jan - Sep)	$45.80	$45.73	$0.05	$0.02

14 The years 2006 and 2007 were removed from Table 2-32 and Table 2-34 because PJM did not begin to include marginal losses in economic dispatch and LMP models until June 1, 2007.

Zonal and PJM Real-Time, Load-Weighted, Average LMP Components

Table 2-33 PJM day-ahead, simple average LMP components (Dollars per MWh): January through September 2008 to 2011 (See 2010 SOM, Table 2-54)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008 (Jan - Sep)	$71.43	$71.78	($0.12)	($0.23)
2009 (Jan - Sep)	$37.35	$37.52	($0.07)	($0.10)
2010 (Jan - Sep)	$45.81	$45.76	$0.08	($0.03)
2011 (Jan - Sep)	$45.14	$45.34	($0.06)	($0.14)

Marginal Loss Costs and Loss Credits

Table 2-34 Marginal loss costs and loss credits: January through September 2008 to 2011 (See 2010 SOM, Table 2-57)

	Total Marginal Loss Costs	Loss Credits	Percent
2008 (Jan - Sep)	$2,041,052,829	$1,073,973,038	52.6%
2009 (Jan - Sep)	$992,759,421	$508,471,294	51.2%
2010 (Jan - Sep)	$1,259,207,969	$639,883,695	50.8%
2011 (Jan - Sep)	$1,152,612,642	$502,066,337	43.6%

Monthly Marginal Loss Costs

Table 2-35 Marginal loss costs by type (Dollars (Millions)): January through September 2011 (See 2010 SOM, Table 2-58)

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$41.8	($134.4)	$12.3	$188.5	$4.4	$1.9	($5.4)	($2.9)	$185.7
Feb	$26.8	($88.2)	$6.8	$121.8	$2.4	$2.3	($1.9)	($1.8)	$119.9
Mar	$22.9	($79.1)	$6.8	$108.8	$1.1	$2.2	($3.8)	($4.8)	$104.0
Apr	$18.3	($63.1)	$3.4	$84.8	$1.0	$1.5	($5.1)	($5.6)	$79.2
May	$14.1	($71.2)	$9.0	$94.3	$2.1	$1.9	($7.1)	($7.0)	$87.3
Jun	$17.2	($106.8)	$5.9	$129.9	$2.4	$2.7	($4.3)	($4.5)	$125.4
Jul	$29.6	($184.7)	$3.1	$217.4	$5.7	$5.6	($3.8)	($3.7)	$213.7
Aug	$15.5	($121.3)	$1.2	$137.9	$0.9	$1.6	($2.7)	($3.5)	$134.5
Sep	$11.8	($92.7)	$3.1	$107.7	$4.1	$4.9	($3.9)	($4.7)	$102.9
Total	$197.9	($941.5)	$51.7	$1,191.1	$24.1	$24.6	($38.0)	($38.5)	$1,152.6

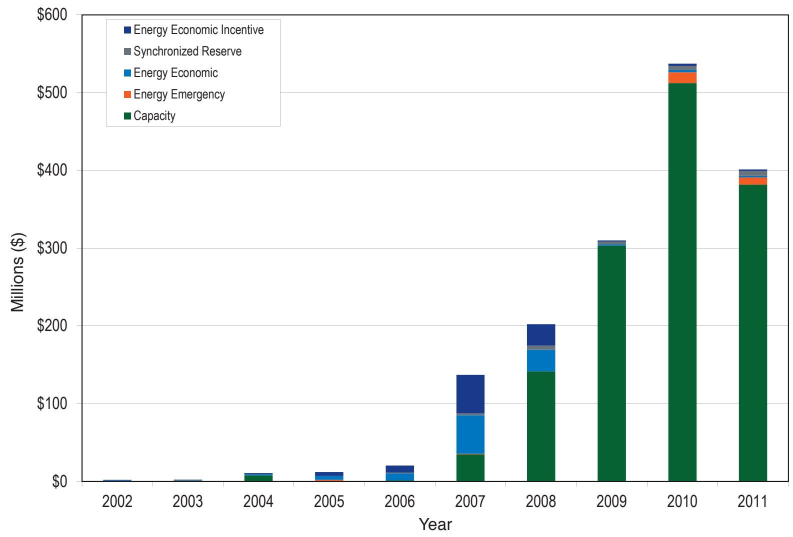
Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-36 Overview of Demand Side Programs (See 2010 SOM, Table 2-72)

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	Voluntary Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment	Energy payment based on submitted higher of “minimum dispatch price” and LMP. Energy payment only for mandatory curtailments.	Energy payment based on submitted higher of “minimum dispatch price” and LMP. Energy payment only for mandatory curtailments.	Energy payment based on LMP less generation component of retail rate. Energy payment for hours of voluntary curtailment.

Figure 2-25 Demand Response revenue by market: Calendar years 2002 through 2010 and January through September 2011 (See 2010 SOM, Figure 2-22)



Economic Program

Table 2-37 Economic Program registration on peak load days: Calendar years 2002 to 2010 and January through September 2011 (See 2010 SOM, Table 2-73)

	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

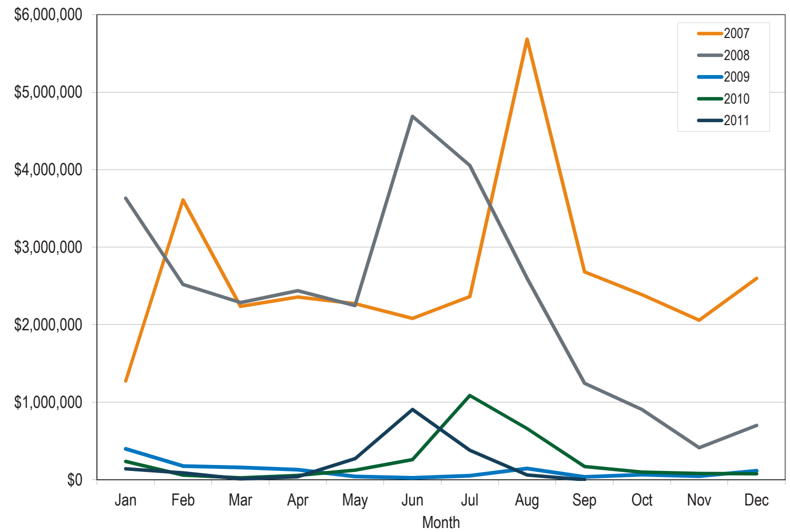
Table 2-38 Economic Program registrations on the last day of the month: January 2008 through September 2011 (See 2010 SOM, Table 2-74)

	2008		2009		2010		2011	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	4,906	2,959	4,862	3,303	1,841	2,623	1,607	2,449
Feb	4,902	2,961	4,869	3,219	1,842	2,624	1,612	2,454
Mar	4,972	3,012	4,867	3,227	1,845	2,623	1,610	2,537
Apr	5,016	3,197	2,582	3,242	1,849	2,587	1,611	2,534
May	5,069	3,588	1,250	2,860	1,875	2,819	1,600	2,482
Jun	3,112	3,014	1,265	2,461	813	1,608	1,136	1,849
Jul	4,542	3,165	1,265	2,445	1,192	2,159	1,228	2,062
Aug	4,815	3,232	1,653	2,650	1,616	2,398	1,982	2,194
Sep	4,836	3,263	1,879	2,727	1,609	2,447	1,960	2,181
Oct	4,846	3,266	1,875	2,730	1,606	2,444		
Nov	4,851	3,271	1,874	2,730	1,605	2,444		
Dec	4,851	3,290	1,853	2,627	1,598	2,439		
Avg.	4,727	3,185	2,508	2,852	1,608	2,435	1,594	2,305

Table 2-39 Distinct registrations and sites in the Economic Program: July 21, 2011[15] (See 2010 SOM, Table 2-75)

	Registrations	Sites	MW
AECO	30	33	15.2
AEP	53	104	102.8
AP	132	211	102.3
ATSI	6	6	75.5
BGE	50	59	588.7
ComEd	72	100	92.1
DAY	6	16	7.9
DLCO	33	38	59.7
Dominion	89	93	197.1
DPL	33	39	63.4
JCPL	25	33	120.8
Met-Ed	72	80	84.5
PECO	249	310	142.2
PENELEC	138	169	103.4
Pepco	18	22	14.6
PPL	140	223	225.6
PSEG	90	152	45.8
RECO	1	1	0.3
Total	1,237	1,689	2,041.8

Figure 2-26 Economic Program payments by month: Calendar years 2007[16] through 2010 and January through September 2011 (See 2010 SOM, Figure 2-23)



15 Effective July 1, 2009, PJM implemented a new eSuite application, Load Response System (eLRS) to serve as the interface for collecting and storing customer registration and settlement data. With the implementation of the LRS system, more detail is available on customer registrations and, as a result, there is an enhanced ability to capture multiple distinct locations aggregated to a single registration. The second column of Table 2-39 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

16 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 2-26 do not include these incentive payments.

Table 2-40 PJM Economic Program participation by zone: January through September 2010 and 2011 (See 2010 SOM, Table 2-78)

	Credits			MWh Reductions		
	2010	2011	Percent Change	2010	2011	Percent Change
AECO	$5,026	$0	(100%)	86.7	0.0	(100%)
AEP	$56	$24,279	43,293%	7.0	310.0	4,315%
AP	$118,785	$16,756	(86%)	3,851.0	327.1	(92%)
ATSI	$0	$1,829	NA	0.0	19.4	NA
BGE	$445,908	$730,278	64%	3,679.3	2,294.5	(38%)
ComEd	$39,796	$2,420	(94%)	2,286.8	197.4	(91%)
DAY	$1,173	$13,435	1,046%	11.2	18.8	68%
DLCO	$0	$961,780	NA	0.0	9,104.6	NA
Dominion	$1,403,641	$59	(100%)	26,359.2	0.4	(100%)
DPL	$248	$518	109%	0.9	12.1	1,187%
JCPL	$20,539	$1,075	(95%)	235.5	3.3	(99%)
Met-Ed	$1,359	$15,768	1,060%	32.7	140.8	331%
PECO	$620,653	$76,660	(88%)	21,088.2	1,629.2	(92%)
PENELEC	$918	$206	(78%)	42.5	6.6	(85%)
Pepco	$3,106	$2,630	(15%)	58.2	37.8	(35%)
PPL	$15,249	$46,021	202%	479.2	187.6	(61%)
PSEG	$1,458	$4,467	206%	61.5	25.7	(58%)
RECO	$24	$0	(100%)	0.4	0.0	(100%)
Total	$2,677,937	$1,898,180	(29%)	58,280.1	14,315.1	(75%)

Table 2-41 Settlement days submitted by month in the Economic Program: Calendar years 2008 through 2010 and January through September 2011 (See 2010 SOM, Table 2-79)

Month	2007	2008	2009	2010	2011
Jan	937	2,916	1,264	1,415	562
Feb	1,170	2,811	654	546	148
Mar	1,255	2,818	574	411	82
Apr	1,540	3,406	337	338	102
May	1,649	3,336	918	673	298
Jun	1,856	3,184	2,727	1,221	743
Jul	2,534	3,339	2,879	3,007	1,411
Aug	3,962	3,848	3,760	2,158	790
Sep	3,388	3,264	2,570	660	294
Oct	3,508	1,977	2,361	699	
Nov	2,842	1,105	2,321	672	
Dec	2,675	986	1,240	894	
Total	26,423	32,990	21,605	12,694	4,430

Table 2-42 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2010 and January through September 2011 (See 2010 SOM, Table 2-80)

	2008		2009		2010		2011	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	13	261	17	257	11	162	5	40
Feb	13	243	12	129	9	92	6	29
Mar	11	216	11	149	7	124	3	15
Apr	12	208	9	76	5	77	3	15
May	12	233	9	201	6	140	6	144
Jun	17	317	20	231	11	152	10	304
Jul	16	295	21	183	18	243	15	214
Aug	17	306	15	400	14	302	14	186
Sep	17	312	11	181	11	97	7	47
Oct	13	226	11	93	8	37		
Nov	14	208	9	143	7	40		
Dec	13	193	10	160	7	46		
Total Distinct Active	24	522	25	747	24	438	20	609

Table 2-43 Hourly frequency distribution of Economic Program MWh reductions and credits: January through September 2011 (See 2010 SOM, Table 2-81)

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	6	0.04%	6	0.04%	$105	0.01%	$105	0.01%
2	6	0.04%	12	0.08%	$193	0.01%	$298	0.02%
3	12	0.09%	24	0.17%	$619	0.03%	$917	0.05%
4	4	0.03%	28	0.20%	$61	0.00%	$978	0.05%
5	8	0.06%	36	0.25%	$51	0.00%	$1,028	0.05%
6	36	0.25%	72	0.50%	$725	0.04%	$1,754	0.09%
7	782	5.46%	854	5.97%	$63,897	3.37%	$65,650	3.46%
8	1,080	7.54%	1,934	13.51%	$99,551	5.24%	$165,202	8.70%
9	457	3.19%	2,391	16.70%	$31,684	1.67%	$196,886	10.37%
10	188	1.31%	2,579	18.02%	$8,930	0.47%	$205,815	10.84%
11	164	1.15%	2,743	19.16%	$4,688	0.25%	$210,504	11.09%
12	252	1.76%	2,995	20.92%	$12,390	0.65%	$222,894	11.74%
13	412	2.88%	3,407	23.80%	$33,416	1.76%	$256,310	13.50%
14	644	4.50%	4,051	28.30%	$68,113	3.59%	$324,423	17.09%
15	1,774	12.39%	5,825	40.69%	$332,780	17.53%	$657,203	34.62%
16	2,235	15.61%	8,060	56.30%	$397,131	20.92%	$1,054,334	55.54%
17	2,515	17.57%	10,575	73.87%	$420,253	22.14%	$1,474,587	77.68%
18	2,236	15.62%	12,811	89.49%	$317,993	16.75%	$1,792,580	94.44%
19	1,137	7.95%	13,948	97.44%	$90,586	4.77%	$1,883,166	99.21%
20	122	0.85%	14,070	98.29%	$5,089	0.27%	$1,888,255	99.48%
21	103	0.72%	14,173	99.01%	$5,495	0.29%	$1,893,751	99.77%
22	72	0.50%	14,245	99.51%	$4,051	0.21%	$1,897,801	99.98%
23	49	0.34%	14,294	99.86%	$323	0.02%	$1,898,124	100.00%
24	21	0.14%	14,315	100.00%	$56	0.00%	$1,898,180	100.00%

Table 2-44 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through September 2011 (See 2010 SOM, Table 2-82)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	17	0.12%	17	0.12%	$491	0.03%	$491	0.03%
$25 to $50	1,369	9.56%	1,387	9.69%	$9,608	0.51%	$10,099	0.53%
$50 to $75	2,658	18.56%	4,044	28.25%	$47,166	2.48%	$57,265	3.02%
$75 to $100	1,286	8.99%	5,330	37.24%	$51,631	2.72%	$108,896	5.74%
$100 to $125	1,196	8.35%	6,526	45.59%	$72,837	3.84%	$181,733	9.57%
$125 to $150	1,179	8.23%	7,705	53.82%	$105,371	5.55%	$287,105	15.13%
$150 to $200	2,032	14.19%	9,737	68.02%	$247,785	13.05%	$534,890	28.18%
$200 to $250	1,184	8.27%	10,921	76.29%	$196,496	10.35%	$731,386	38.53%
$250 to $300	961	6.71%	11,881	83.00%	$208,241	10.97%	$939,627	49.50%
> $300	2,434	17.00%	14,315	100.00%	$958,553	50.50%	$1,898,180	100.00%

Emergency Program

Load Management Program

Table 2-45 Zonal monthly capacity credits: January through September 2011 (See 2010 SOM, Table 2-85)

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$515,251	$465,388	$515,251	$498,630	$515,251	$332,740	$343,831	$343,831	$332,740	$3,862,912
AEP	$7,718,744	$6,971,769	$7,718,744	$7,469,752	$7,718,744	$5,220,226	$5,394,234	$5,394,234	$5,220,226	$58,826,674
APS	$4,272,819	$3,859,321	$4,272,819	$4,134,986	$4,272,819	$3,300,774	$3,410,799	$3,410,799	$3,300,774	$34,235,911
ATSI	$0	$0	$0	$0	$0	$4,665	$4,821	$4,821	$4,665	$18,971
BGE	$5,039,828	$4,552,103	$5,039,828	$4,877,253	$5,039,828	$3,513,455	$3,630,571	$3,630,571	$3,513,455	$38,836,891
ComEd	$8,156,971	$7,367,587	$8,156,971	$7,893,843	$8,156,971	$5,965,794	$6,180,266	$6,180,266	$5,980,903	$64,039,573
DAY	$1,151,545	$1,040,105	$1,151,545	$1,114,399	$1,151,545	$797,889	$824,485	$824,485	$797,889	$8,853,888
DLCO	$1,118,544	$1,010,298	$1,118,544	$1,082,462	$1,118,544	$2,340	$2,418	$2,418	$2,340	$5,457,909
Dominion	$5,447,494	$4,920,317	$5,447,494	$5,271,768	$5,447,494	$3,851,851	$3,980,247	$3,980,247	$3,851,851	$42,198,763
DPL	$1,088,233	$982,920	$1,088,233	$1,053,128	$1,088,233	$790,970	$817,336	$817,336	$790,970	$8,517,360
JCPL	$1,301,034	$1,175,128	$1,301,034	$1,259,066	$1,301,034	$854,729	$883,220	$883,220	$854,729	$9,813,193
Met-Ed	$1,205,089	$1,088,468	$1,205,089	$1,166,215	$1,205,089	$880,176	$909,516	$909,516	$880,176	$9,449,333
PECO	$2,826,229	$2,552,723	$2,826,229	$2,735,060	$2,826,229	$2,300,272	$2,376,947	$2,376,947	$2,300,272	$23,120,907
PENELEC	$1,827,610	$1,650,744	$1,827,610	$1,768,654	$1,827,610	$1,335,716	$1,380,240	$1,380,240	$1,335,716	$14,334,140
Pepco	$1,307,359	$1,180,840	$1,307,359	$1,265,186	$1,307,359	$1,137,037	$1,174,938	$1,174,938	$1,137,037	$10,992,052
PPL	$4,115,164	$3,716,922	$4,115,164	$3,982,417	$4,115,164	$2,651,235	$2,739,610	$2,739,610	$2,651,235	$30,826,522
PSEG	$2,536,813	$2,291,315	$2,536,813	$2,454,980	$2,536,813	$1,431,581	$1,479,301	$1,479,301	$1,431,581	$18,178,499
RECO	$9,266	$8,369	$9,266	$8,967	$9,266	$21,799	$22,526	$22,526	$21,799	$133,784
Total	$49,637,993	$44,834,317	$49,637,993	$48,036,767	$49,637,993	$34,393,250	$35,555,305	$35,555,305	$34,408,359	$381,697,282

SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance in the first nine months of 2011. As part of the review of market performance, the MMU analyzed the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Highlights

- Net revenue performance was the result of capacity market prices, which declined in all LDAs except rest of RTO and energy market prices which were lower for most zones. Combustion turbine (CT) net revenues were lower in ten zones and higher in six zones, including four zones where net revenues increased by more than 20 percent. Combined Cycle (CC) net revenues were lower in eleven zones and higher in five zones, including three zones where net revenues increased by more than 20 percent. Coal Plant (CP) net revenues were lower in twelve zones and higher in four zones, including one zone where net revenues increased by more than 20 percent.

- There were no scarcity pricing events in the first nine months of 2011 under PJM's current Emergency Action based scarcity pricing rules.

- Operating reserve charges increased $83,751,028, or 20.5 percent, from $408,267,759 in the first nine months of 2010, to $492,018,787 in the first nine months of 2011. Reliability credits decreased $7,716,442, or 9.4 percent, in the first nine months of 2011 compared to the first nine months of 2010, and deviation credits increased $263,011,867, or 184.3 percent.

- Reliability charges were $74,733,573, 15.6 percent of all balancing operating reserve charges for the first nine months 2011, a decrease of $7,801,659 or 9.4 percent from the first nine months of 2010. Deviation charges were $405,744,328, or 84.4 percent in the first nine months of 2011, an increase of $262,622,763, or 183.5 percent from the first nine months of 2010.

- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 29.7 percent of total operating reserve credits in the first nine months of 2011, compared to 36.4 percent in the first nine months of 2010. In the first nine months of 2011, the top generation owner received 22.7 percent of the total operating reserve credits paid.

- The regional concentration of balancing operating reserves for the first nine months of 2011 is higher than the first nine months of 2010, with 28.7 percent of the credits paid to units operating in the Dominion zone, 21.8 percent in the PSEG zone, and 10.1 percent in the AEP zone.

- In the first nine months of 2011, coal units provided 48.2 percent, nuclear units 33.8 percent and gas units 13.8 percent of total generation. Compared to the first nine months of 2010, generation from coal units decreased 0.3 percent, and generation from nuclear units increased 1.5 percent, while generation from natural gas units increased 24.4 percent, and generation from oil units decreased 29.5 percent.

- At the end of September 2011, 86,864 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 180,000 MW in 2011 since the June 1, 2011, ATSI integration. Wind projects account for approximately 39,459 MW of capacity, 45.4 percent of the capacity in the queues and combined-cycle projects account for 26,785 MW, 30.8 percent, of the capacity in the queues.

- Three large plants (over 550 MW) started generating in PJM since January 1, 2011. These include York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, and Longview Power in the APS zone. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 3,639 MW of nameplate capacity was added in PJM in 2011 (excluding the ATSI zone additions), the most since 2002.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Total fixed costs, in this sense, include all but short run variable costs.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total 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 and in existing generation to serve PJM markets. Net revenue is the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources when there is a market based need, 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.

- **Net Revenue.** Net revenue performance was the result of capacity market prices, which declined in all LDAs except rest of RTO and energy market prices which were lower for most zones. Combustion turbine (CT) net revenues were lower in ten zones and higher in six zones, including four zones where net revenues increased by more than 20 percent (Table 3-6). Combined Cycle (CC) net revenues were lower in eleven zones and higher in five zones, including three zones where net revenues increased by more than 20 percent (Table 3-8). Coal Plant (CP) net revenues were lower in twelve zones and higher in four zones, including one zone where net revenues increased by more than 20 percent (Table 3-10).

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through September 30, 2011, PJM installed capacity resources increased from 166,410.2 MW on January 1 to 179,571.6 as a result of the integration of the American Transmission Systems, Inc. (ATSI) Control Zone into PJM.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of September 30, 2011, 41.9 percent was coal; 28.2 percent was gas; 18.5 percent was nuclear; 6.2 percent was oil; 4.5 percent was hydroelectric; 0.4 percent was solid waste, 0.4 percent was wind, and 0.0 percent was solar.

- **Generation Fuel Mix.** During the period January 1 through September 2011, coal units provided 48.2 percent, nuclear units 33.8 percent and gas units 13.8 percent of total generation. Compared to the first nine months of 2010, generation from coal units decreased 0.3 percent, generation from nuclear units increased 1.5 percent, generation from natural gas units increased 24.4 percent, and generation from oil units decreased 29.5 percent.

- **Planned Generation.** 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, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Environmental Rules

- **Cross-State Air Pollution Rule.** On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), a rule that requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS).[1] CSAPR will cover 28 states, including all of the PJM states except Delaware, and also excepting the District of Columbia.[2] This rule replaces a 2005 rule known as the Clean Air Interstate Rule (CAIR), which has been in effect temporarily while the EPA developed a successor rule responding to an order of the U.S. Court of Appeals for the District of Columbia Circuit directing revisions compliant with the requirements of the Clean Air Act. The CSAPR and its initial emissions caps will become effective January 1, 2012. Two years later, on January 1, 2014, those emission caps will drop substantially.

  CSPAR establishes two groups of states with separate requirements standards. "Group 1" includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excepting the District of Columbia.[3] "Group 2" does not include any states in the PJM region.[4] Group 1 states must reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual PM2.5 NAAQS and to reduce ozone season NO_X emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS.

  Emission reductions are effective starting January 1, 2012, for SO_2 and annual NO_X reductions and May 1, 2012, for ozone season NO_X reductions. CSAPR requires reductions of emissions for each state below certain "assurance levels," established separately for each emission type. Assurance levels are the state allowance budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a "variability limit," an additional level of allowances that may be obtained by trading for allowances allocated to out of state units in states included in the same group.

  Significant additional SO_2 emission reductions are required in 2014 from certain states, including all of the PJM states except Delaware, and also excepting the District of Columbia.

  EPA estimates that by 2014 this rule and other federal rules will lower power plant annual emissions of SO_2, NO_X from 2005 levels in the CSAPR region by 73 percent (6.4 million tons/year) and 54 percent (1.4 million tons/year).

  The rule implements a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group. Thus, PJM states may only trade with other Group 1 states.

  If state emissions exceed the applicable assurance level, including the variability limit, a penalty will be assessed that is allocated to resources within the state in proportion to their responsibility for the excess. The penalty will be a requirement to surrender two additional allowances for each allowance needed to the cover the excess. In response to concerns raised by stakeholders about the liquidity of allowance trading markets upon implementation of CSAPR on January 1, 2012, the EPA has postponed the assessment of assurance level penalty provisions until January 1, 2014.[5]

- **EPA Mercury Air Toxics Standards Proposed Rule.** On March 16, 2011, the EPA issued a notice of proposed rulemaking that would apply the Clean Air Act's maximum achievable control technology (MACT) requirement to new or modified sources of mercury and acid gas emissions. The EPA plans to finalize the rule in November 2011. It is proposed to become effective in 2015. The Clean Air Act defines MACT as the average emission rate of the best performing 12 percent of existing resources.

- **EPA Greenhouse Gas Tailoring Rule.** On May 13, 2010, the EPA issued a rule regulating CO_2 and other greenhouse gas emissions under

1 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011).
2 76 Fed. Reg. 40662 (July 11, 2011) (Proposed Revised CSAPR).
3 Group 1 states include PJM states: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.
4 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.
5 *See* Proposed Revised CSAPR II at 63870.

the existing framework of new source review (NSR) and prevention of significant deterioration (PSD). As a result, new or modified units that increase emissions must install or implement the best available control technology (BACT). State environmental regulators determine BACT project by project, with guidance from the EPA.

- **NJ High Energy Demand Day (HEDD) Rule.** The EPA's transport rules, which apply to annual and seasonal emissions, affect units based on total annual or seasonal emissions. Units with relatively low capacity factors have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules. The New Jersey Department of Environmental Protection estimates that regulations targeting such units have the potential for region wide emission reductions of 1–2 ppb and greater localized reductions.[6]

  New Jersey has 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 Energy Demand Days" or "HEDD," and imposes operational restrictions and emissions control requirements on units responsible for significant NO_x emissions on HEDD. New Jersey's HEDD rule,[7] 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.[8]

  New Jersey's HEDD rule will be implemented in two phases. For the first and currently effective phase, owners/operators of HEDD units have prepared a 2009 HEDD Emission Reduction Compliance Demonstration Protocol (HEDD Protocol) and obtained the approval of the New Jersey Department of Environmental Protection. A HEDD Protocol may include the following measures: 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 a 2015 HEDD Emission Limit Achievement Plan by May 1, 2010, describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_x emission rates.

6 *See* Tonalee Carlson Key, New Jersey Department of Environmental Protection, "Electric Generation on High Electric Demand Days," presentation at annual public hearing (April 1, 2009) at 11–12. This document may be accessed at: <http://www.state.nj.us/dep/cleanair/hearings/powerpoint/09_electric_gen.ppt>.
7 N.J.A.C. § 7:27–19.
8 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).

Scarcity

- **Scarcity Pricing Events in the first nine months of 2011.** PJM did not declare a scarcity event in the first nine months of 2011.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole payments, operating reserve credits 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. From the perspective of those participants paying the 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 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.

- **Operating Reserve Charges in the first nine months of 2011.** Operating reserve charges increased 20.5 percent in the first nine months of 2011 compared to the first nine months of 2010. Reliability credits decreased $7,716,442, or 9.4 percent, in the first nine months of 2011 compared to the first nine months of 2010, and deviation credits increased $263,011,867, or 184.3 percent.

  The overall increase in operating reserve charges in 2011 is comprised of a 6.4 percent increase in day-ahead operating reserve charges, a 21.0 percent increase in synchronous condensing charges and a 23.1 percent increase in balancing operating reserve charges. Much of the increase came due to weather events in July, when operating reserve charges increased 64 percent.

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.

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. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

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 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 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.

Coal plants (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are reduced and there is little contribution to fixed costs. In addition, coal plants had, on average across all zones, 31 fewer profitable days in the first nine months of 2011 as compared to the first nine months of 2010.

Net Revenue

Capacity Market Net Revenue

Table 3-1 Capacity revenue by PJM zones (Dollars per MW-year): January through September 2010 and 2011[9] (See 2010 SOM, Table 3-4)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$46,178	$36,675	(21%)
AEP	$33,384	$36,066	8%
AP	$46,330	$36,677	(21%)
ATSI	NA	NA	NA
BGE	$52,392	$36,730	(30%)
ComEd	$33,884	$36,720	8%
DAY	$33,961	$36,500	7%
DLCO	$33,599	$36,342	8%
Dominion	$46,597	$37,157	(20%)
DPL	$33,757	$36,434	8%
JCPL	$46,162	$36,436	(21%)
Met-Ed	$46,232	$36,590	(21%)
PECO	$46,334	$36,706	(21%)
PENELEC	$46,450	$36,693	(21%)
Pepco	$46,401	$36,622	(21%)
PPL	$46,270	$36,748	(21%)
PSEG	$50,165	$36,466	(27%)
RECO	NA	NA	NA
PJM	$41,002	$36,549	(11%)

9 The capacity market revenues reflect modifications to the calculations from prior State of the Market Reports. The calculations here reflect payments to generation capacity resources by zone. The RECO zone is reported as NA because there are no capacity resources in the RECO zone.

New Entrant Net Revenues[10,11]

Table 3-2 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year):[12,13] Net revenue for January through September 2010 and 2011 (See 2010 SOM, Table 3-5)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$48,990	$51,299	5%
AEP	$11,188	$22,761	103%
AP	$28,773	$36,860	28%
ATSI	NA	$15,660	NA
BGE	$60,741	$56,754	(7%)
ComEd	$10,105	$17,278	71%
DAY	$11,190	$24,349	118%
DLCO	$16,445	$26,295	60%
Dominion	$50,962	$45,652	(10%)
DPL	$48,046	$46,524	(3%)
JCPL	$42,847	$50,124	17%
Met-Ed	$45,207	$44,234	(2%)
PECO	$41,936	$46,675	11%
PENELEC	$19,533	$36,480	87%
Pepco	$56,186	$47,246	(16%)
PPL	$38,739	$46,774	21%
PSEG	$42,398	$44,259	4%
RECO	$37,754	$34,734	(8%)
PJM	$35,944	$38,553	7%

10 New entrant units are assumed to operate at full output.
11 Fuel prices are calculated by zone. PEPCO zone gas costs differ from the gas costs used in prior State of the Market Reports.
12 The energy net revenues presented for the PJM area for 2010 and 2011 in this section represent the simple average of all zonal energy net revenues.
13 The capacity market revenues reflect modifications to the calculations from prior State of the Market Reports. The calculations here assume that the CT plant could be dispatched by PJM operations in blocks of a minimum of four hours from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any block in which the revenue generated was greater than the cost to generate, including the cost for a complete startup.

Table 3-3 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch[14] (Dollars per installed MW-year): Net revenue for January through September 2010 and 2011 (See 2010 SOM, Table 3-6)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$88,359	$88,757	0%
AEP	$33,754	$48,752	44%
AP	$61,722	$71,534	16%
ATSI	NA	$29,877	NA
BGE	$101,923	$92,769	(9%)
ComEd	$29,833	$36,456	22%
DAY	$34,624	$50,143	45%
DLCO	$37,460	$51,939	39%
Dominion	$88,251	$79,822	(10%)
DPL	$87,707	$82,706	(6%)
JCPL	$81,576	$86,333	6%
Met-Ed	$82,249	$77,409	(6%)
PECO	$79,271	$81,493	3%
PENELEC	$48,062	$70,440	47%
Pepco	$95,916	$80,683	(16%)
PPL	$73,798	$80,164	9%
PSEG	$82,150	$80,054	(3%)
RECO	$74,608	$65,415	(12%)
PJM	$69,486	$69,708	0%

Table 3-4 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for January through September 2010 and 2011 (See 2010 SOM, Table 3-7)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$133,621	$90,567	(32%)
AEP	$56,105	$79,589	42%
AP	$89,006	$107,386	21%
ATSI	NA	$31,502	NA
BGE	$78,725	$75,345	(4%)
ComEd	$100,302	$99,831	(0%)
DAY	$73,987	$73,715	(0%)
DLCO	$72,909	$62,239	(15%)
Dominion	$125,086	$88,932	(29%)
DPL	$131,552	$106,446	(19%)
JCPL	$126,946	$86,767	(32%)
Met-Ed	$125,845	$72,970	(42%)
PECO	$123,518	$81,267	(34%)
PENELEC	$99,601	$96,853	(3%)
Pepco	$138,370	$83,840	(39%)
PPL	$104,880	$89,931	(14%)
PSEG	$110,494	$62,399	(44%)
RECO	$120,939	$68,304	(44%)
PJM	$106,582	$80,994	(24%)

14 All starts associated with combined cycle units are assumed to be hot starts.

New Entrant Combustion Turbine

Table 3-5 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-8)

	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
Energy	$35,944	$38,553	7%
Capacity	$40,290	$35,914	(11%)
Synchronized	$0	$0	NA
Regulation	$0	$0	NA
Reactive	$1,794	$1,794	0%
Total	$78,027	$76,261	(2%)

Table 3-6 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-9)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$96,160	$89,131	(7%)
AEP	$45,786	$59,994	31%
AP	$76,092	$74,694	(2%)
ATSI	NA	NA	NA
BGE	$114,017	$94,639	(17%)
ComEd	$45,194	$55,155	22%
DAY	$46,355	$62,009	34%
DLCO	$51,254	$63,799	24%
Dominion	$98,544	$83,957	(15%)
DPL	$83,010	$84,119	1%
JCPL	$90,001	$87,722	(3%)
Met-Ed	$92,429	$81,982	(11%)
PECO	$89,258	$84,537	(5%)
PENELEC	$66,969	$74,329	11%
Pepco	$103,574	$85,026	(18%)
PPL	$85,999	$84,678	(2%)
PSEG	$93,485	$81,886	(12%)
RECO	NA	NA	NA
PJM	$78,027	$76,261	(2%)

New Entrant Combined Cycle

Table 3-7 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-10)

	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
Energy	$69,486	$69,708	0%
Capacity	$42,570	$37,947	(11%)
Synchronized	$0	$0	NA
Regulation	$0	$0	NA
Reactive	$2,392	$2,392	0%
Total	$114,448	$110,047	(4%)

Table 3-8 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-11)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$138,694	$129,227	(7%)
AEP	$70,807	$88,589	25%
AP	$112,215	$112,005	(0%)
ATSI	NA	NA	NA
BGE	$158,710	$133,295	(16%)
ComEd	$67,404	$76,972	14%
DAY	$72,275	$90,430	25%
DLCO	$74,736	$92,062	23%
Dominion	$139,021	$120,791	(13%)
DPL	$125,146	$122,926	(2%)
JCPL	$131,895	$126,554	(4%)
Met-Ed	$132,640	$117,790	(11%)
PECO	$129,769	$121,995	(6%)
PENELEC	$98,679	$110,927	12%
Pepco	$146,483	$121,097	(17%)
PPL	$124,229	$120,709	(3%)
PSEG	$136,625	$120,306	(12%)
RECO	NA	NA	NA
PJM	$114,448	$110,047	(4%)

New Entrant Coal Plant

Table 3-9 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-12)

	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
Energy	$106,582	$80,994	(24%)
Capacity	$39,844	$35,517	(11%)
Synchronized	$0	$0	NA
Regulation	$896	$773	(14%)
Reactive	$1,334	$1,334	0%
Total	$148,655	$118,617	(20%)

Table 3-10 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-13)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$180,624	$128,304	(29%)
AEP	$90,899	$116,589	28%
AP	$136,231	$144,923	6%
ATSI	NA	NA	NA
BGE	$132,335	$113,333	(14%)
ComEd	$135,488	$137,550	2%
DAY	$109,214	$111,168	2%
DLCO	$107,974	$99,620	(8%)
Dominion	$172,546	$127,185	(26%)
DPL	$166,491	$143,884	(14%)
JCPL	$173,938	$124,290	(29%)
Met-Ed	$172,915	$110,704	(36%)
PECO	$170,689	$119,060	(30%)
PENELEC	$146,864	$134,448	(8%)
Pepco	$185,614	$121,533	(35%)
PPL	$152,060	$127,737	(16%)
PSEG	$161,437	$100,292	(38%)
RECO	NA	NA	NA
PJM	$148,655	$118,617	(20%)

New Entrant Day-Ahead Net Revenues

Table 3-11 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-14)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$30,036	$33,837	13%
AEP	$5,893	$12,434	111%
AP	$17,788	$21,466	21%
ATSI	NA	$10,773	NA
BGE	$38,886	$34,388	(12%)
ComEd	$5,748	$8,369	46%
DAY	$6,276	$12,045	92%
DLCO	$8,888	$13,449	51%
Dominion	$31,136	$24,743	(21%)
DPL	$28,597	$30,982	8%
JCPL	$26,864	$30,003	12%
Met-Ed	$28,028	$26,490	(5%)
PECO	$26,553	$31,895	20%
PENELEC	$13,070	$21,016	61%
Pepco	$35,713	$29,883	(16%)
PPL	$22,978	$27,969	22%
PSEG	$25,791	$24,758	(4%)
RECO	$23,689	$19,356	(18%)
PJM	$22,114	$22,992	4%

Table 3-12 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-15)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$75,960	$82,661	9%
AEP	$28,883	$43,814	52%
AP	$55,887	$66,249	19%
ATSI	NA	$27,176	NA
BGE	$89,383	$80,748	(10%)
ComEd	$24,712	$28,505	15%
DAY	$29,248	$43,384	48%
DLCO	$33,423	$44,528	33%
Dominion	$79,295	$68,259	(14%)
DPL	$74,926	$77,866	4%
JCPL	$72,689	$78,561	8%
Met-Ed	$70,770	$68,927	(3%)
PECO	$70,477	$78,389	11%
PENELEC	$47,225	$63,573	35%
Pepco	$86,210	$74,208	(14%)
PPL	$62,788	$70,737	13%
PSEG	$71,719	$70,305	(2%)
RECO	$66,646	$57,895	(13%)
PJM	$61,191	$62,544	2%

Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-16)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$129,484	$85,659	(34%)
AEP	$53,672	$78,816	47%
AP	$87,301	$105,478	21%
ATSI	NA	$29,359	NA
BGE	$69,319	$61,798	(11%)
ComEd	$98,853	$98,106	(1%)
DAY	$71,194	$70,724	(1%)
DLCO	$73,448	$56,837	(23%)
Dominion	$125,057	$81,308	(35%)
DPL	$127,368	$105,693	(17%)
JCPL	$127,014	$79,412	(37%)
Met-Ed	$123,359	$64,994	(47%)
PECO	$123,973	$78,979	(36%)
PENELEC	$105,031	$92,737	(12%)
Pepco	$139,062	$79,580	(43%)
PPL	$102,670	$82,458	(20%)
PSEG	$109,538	$53,125	(52%)
RECO	$124,402	$66,509	(47%)
PJM	$105,338	$76,198	(28%)

Table 3-14 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through September 2011 (See 2010 SOM, Table 3-17)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,182	62%
2008	$12,442	$6,623	$5,819	47%
2009	$13,384	$6,030	$7,354	55%
2010	$42,604	$24,485	$18,120	43%
2011 (Jan - Sep)	$38,553	$22,992	$15,561	40%

Table 3-15 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through September 2011 (See 2010 SOM, Table 3-18)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,632	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,195	20%
2006	$44,692	$31,670	$13,022	29%
2007	$66,616	$44,434	$22,182	33%
2008	$62,039	$47,342	$14,697	24%
2009	$41,211	$39,151	$2,060	5%
2010	$83,555	$72,718	$10,837	13%
2011 (Jan - Sep)	$69,708	$62,544	$7,164	10%

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through September 2011 (See 2010 SOM, Table 3-19)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,160)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,373)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,570	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,266	3%
2009	$69,659	$68,354	$1,305	2%
2010	$128,933	$126,758	$2,176	2%
2011 (Jan - Sep)	$80,994	$76,198	$4,795	6%

Net Revenue Adequacy

Table 3-17 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)): Calendar years 2005 through 2010 (See 2010 SOM, Table 3-20)

	20-Year Levelized Fixed Cost					
	2005	2006	2007	2008	2009	2010
CT	$72,207	$80,315	$90,656	$123,640	$128,705	$131,044
CC	$93,549	$99,230	$143,600	$171,361	$173,174	$175,250
CP	$208,247	$267,792	$359,750	$492,780	$446,550	$465,455

New Entrant Combustion Turbine

Table 3-18 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-22)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$96,160	$89,131	$131,044	73%	68%
AEP	$45,786	$59,994	$131,044	35%	46%
AP	$76,092	$74,694	$131,044	58%	57%
ATSI	NA	NA	$131,044	NA	NA
BGE	$114,017	$94,639	$131,044	87%	72%
ComEd	$45,194	$55,155	$131,044	34%	42%
DAY	$46,355	$62,009	$131,044	35%	47%
DLCO	$51,254	$63,799	$131,044	39%	49%
Dominion	$98,544	$83,957	$131,044	75%	64%
DPL	$83,010	$84,119	$131,044	63%	64%
JCPL	$90,001	$87,722	$131,044	69%	67%
Met-Ed	$92,429	$81,982	$131,044	71%	63%
PECO	$89,258	$84,537	$131,044	68%	65%
PENELEC	$66,969	$74,329	$131,044	51%	57%
Pepco	$103,574	$85,026	$131,044	79%	65%
PPL	$85,999	$84,678	$131,044	66%	65%
PSEG	$93,485	$81,886	$131,044	71%	62%
RECO	NA	NA	$131,044	NA	NA
PJM	$78,027	$76,261	$131,044	60%	58%

Figure 3-1 New entrant CT real-time net revenue for January through September 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): (See 2010 SOM, Figure 3-3)

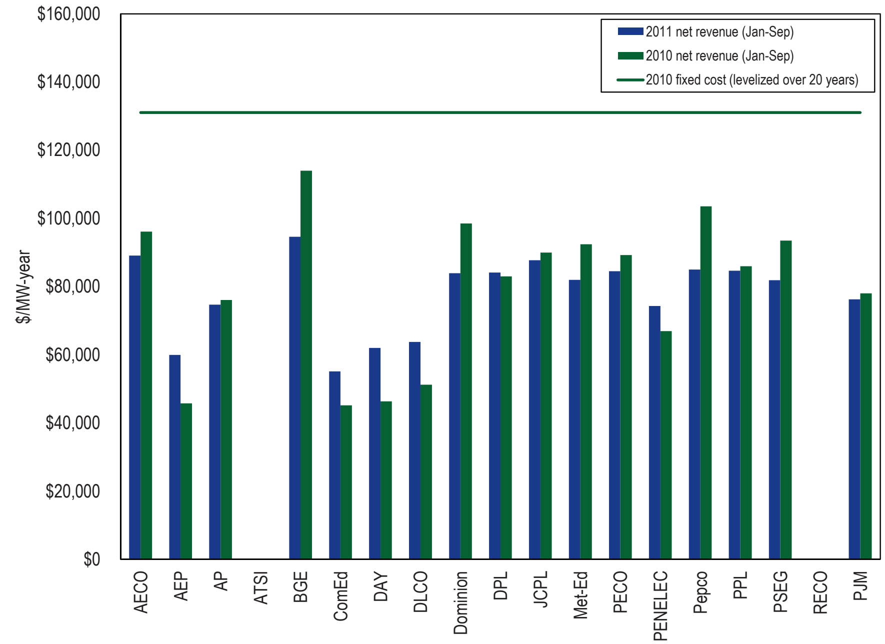
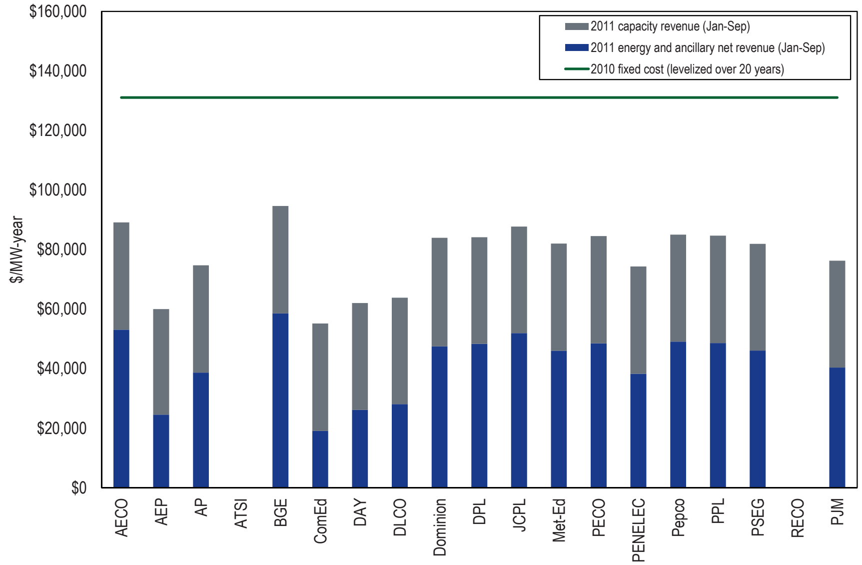


Figure 3-2 New entrant CT zonal real-time January through September 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-4)



New Entrant Combined Cycle

Table 3-19 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-24)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$138,694	$129,227	$175,250	79%	74%
AEP	$70,807	$88,589	$175,250	40%	51%
AP	$112,215	$112,005	$175,250	64%	64%
ATSI	NA	NA	$175,250	NA	NA
BGE	$158,710	$133,295	$175,250	91%	76%
ComEd	$67,404	$76,972	$175,250	38%	44%
DAY	$72,275	$90,430	$175,250	41%	52%
DLCO	$74,736	$92,062	$175,250	43%	53%
Dominion	$139,021	$120,791	$175,250	79%	69%
DPL	$125,146	$122,926	$175,250	71%	70%
JCPL	$131,895	$126,554	$175,250	75%	72%
Met-Ed	$132,640	$117,790	$175,250	76%	67%
PECO	$129,769	$121,995	$175,250	74%	70%
PENELEC	$98,679	$110,927	$175,250	56%	63%
Pepco	$146,483	$121,097	$175,250	84%	69%
PPL	$124,229	$120,709	$175,250	71%	69%
PSEG	$136,625	$120,306	$175,250	78%	69%
RECO	NA	NA	$175,250	NA	NA
PJM	$114,448	$110,047	$175,250	65%	63%

Figure 3-3 New entrant CC real-time net revenue for January through September 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Figure 3-6)

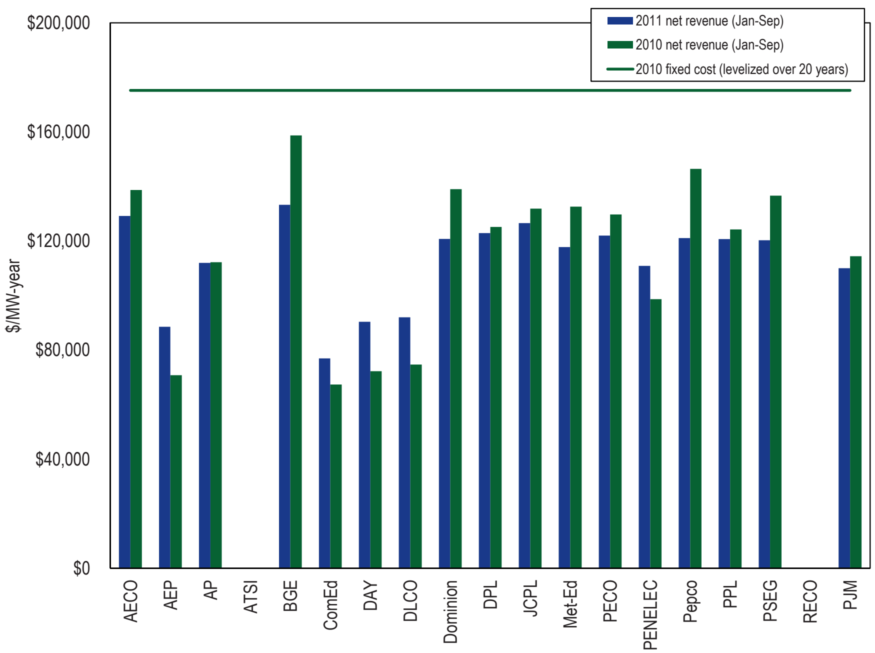
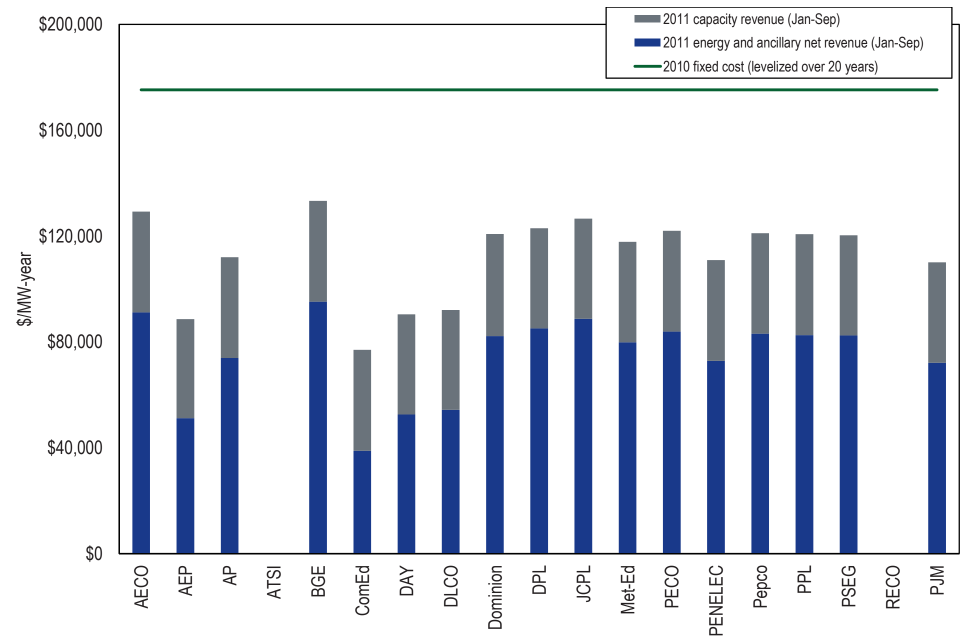


Figure 3-4 New entrant CC zonal real-time January through September 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-7)



New Entrant Coal Plant

Table 3-20 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-26)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$180,624	$128,304	$465,455	39%	28%
AEP	$90,899	$116,589	$465,455	20%	25%
AP	$136,231	$144,923	$465,455	29%	31%
ATSI	NA	NA	$465,455	NA	NA
BGE	$132,335	$113,333	$465,455	28%	24%
ComEd	$135,488	$137,550	$465,455	29%	30%
DAY	$109,214	$111,168	$465,455	23%	24%
DLCO	$107,974	$99,620	$465,455	23%	21%
Dominion	$172,546	$127,185	$465,455	37%	27%
DPL	$166,491	$143,884	$465,455	36%	31%
JCPL	$173,938	$124,290	$465,455	37%	27%
Met-Ed	$172,915	$110,704	$465,455	37%	24%
PECO	$170,689	$119,060	$465,455	37%	26%
PENELEC	$146,864	$134,448	$465,455	32%	29%
Pepco	$185,614	$121,533	$465,455	40%	26%
PPL	$152,060	$127,737	$465,455	33%	27%
PSEG	$161,437	$100,292	$465,455	35%	22%
RECO	NA	NA	$465,455	NA	NA
PJM	$148,655	$118,617	$465,455	32%	25%

Figure 3-5 New entrant CP real-time net revenue for January through March 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Figure 3-9)

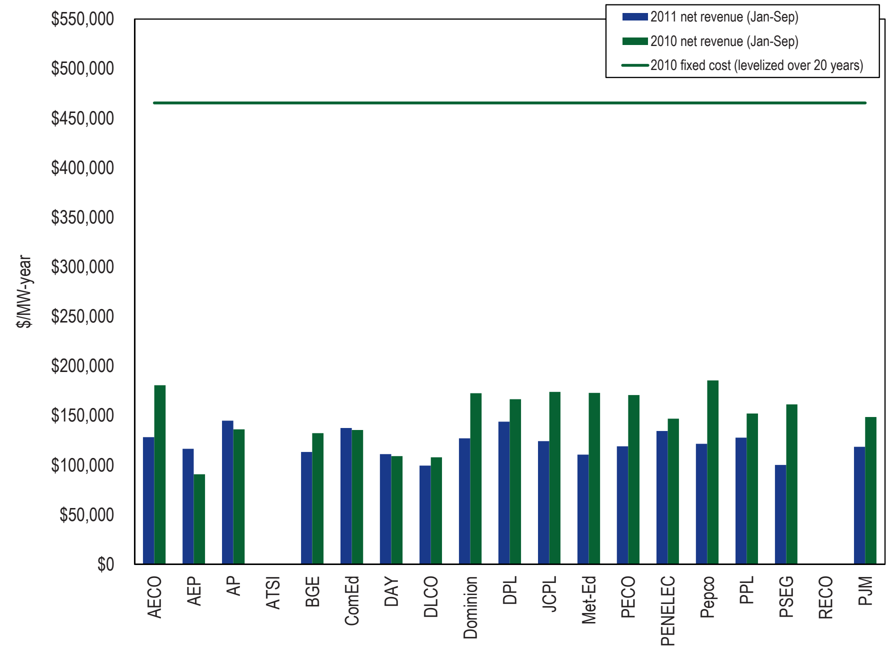
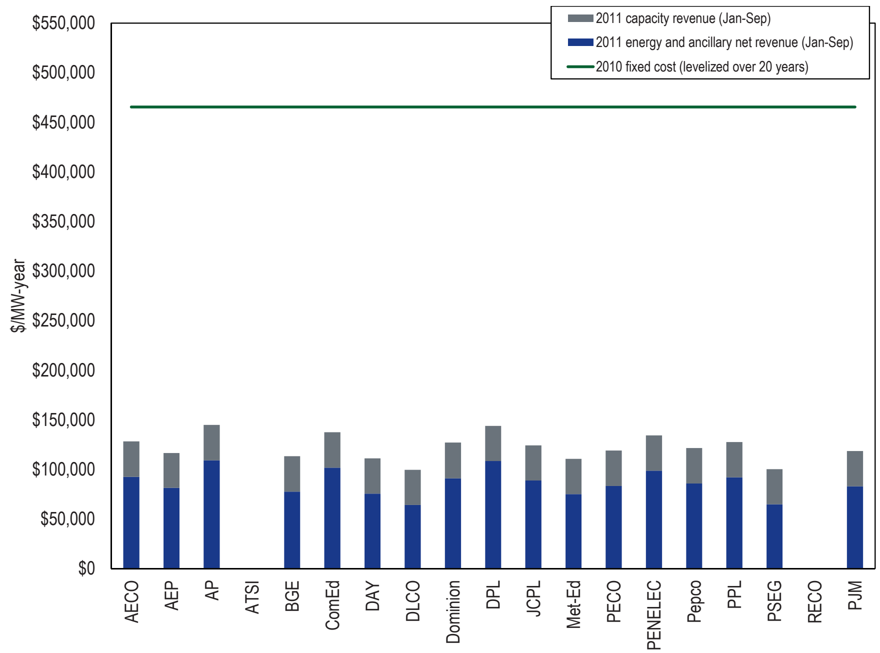


Figure 3-6 New entrant CP zonal real-time January through September 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-10)



Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-21 PJM installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2011 (See 2010 SOM, Table 3-42)

	1-Jan-11		31-May-11		1-Jun-11		30-Sep-11	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,986.0	40.9%	67,879.4	40.7%	76,968.3	42.4%	75,267.3	41.9%
Gas	47,736.6	28.7%	47,831.1	28.7%	50,729.0	28.0%	50,524.5	28.1%
Hydroelectric	7,954.5	4.8%	7,991.8	4.8%	8,029.6	4.4%	8,047.0	4.5%
Nuclear	30,552.2	18.4%	30,822.2	18.5%	33,145.6	18.3%	33,145.6	18.5%
Oil	10,949.5	6.6%	10,854.1	6.5%	11,212.3	6.2%	11,217.3	6.2%
Solar	0.0	0.0%	1.9	0.0%	15.3	0.0%	15.3	0.0%
Solid waste	680.1	0.4%	680.1	0.4%	705.1	0.4%	705.1	0.4%
Wind	551.3	0.3%	551.3	0.3%	633.5	0.3%	649.5	0.4%
Total	166,410.2	100.0%	166,611.9	100.0%	181,438.7	100.0%	179,571.6	100.0%

Energy Production by Fuel Source

Table 3-22 PJM generation (By fuel source (GWh)): January through September 2010 and 2011[15] (See 2010 SOM, Table 3-43)

	2010 (Jan-Sep)		2011 (Jan-Sep)		
	GWh	Percent	GWh	Percent	Change in Output
Coal	279,800.6	49.3%	279,501.2	48.0%	(0.1%)
Standard Coal	270,693.3	47.7%	270,273.8	46.4%	(0.1%)
Waste Coal	9,107.3	1.6%	9,227.4	1.6%	0.0%
Nuclear	192,379.3	33.9%	195,196.7	33.5%	1.5%
Gas	69,803.0	12.3%	82,263.4	14.1%	17.9%
Natural Gas	68,566.0	12.1%	80,907.4	13.9%	18.0%
Landfill Gas	1,236.6	0.2%	1,355.9	0.2%	9.6%
Biomass Gas	0.4	0.0%	0.1	0.0%	(61.6%)
Hydroelectric	11,192.6	2.0%	11,379.8	2.0%	1.7%
Wind	6,173.6	1.1%	7,924.5	1.4%	28.4%
Waste	4,922.3	0.9%	4,254.8	0.7%	(13.6%)
Solid Waste	3,760.1	0.7%	3,318.0	0.6%	(11.8%)
Miscellaneous	1,162.2	0.2%	936.8	0.2%	(19.4%)
Oil	2,956.1	0.5%	2,074.8	0.4%	(29.8%)
Heavy Oil	2,506.1	0.4%	1,711.8	0.3%	(31.7%)
Light Oil	403.2	0.1%	334.3	0.1%	(17.1%)
Diesel	28.0	0.0%	15.9	0.0%	(43.2%)
Kerosene	18.8	0.0%	12.7	0.0%	(32.2%)
Jet Oil	0.1	0.0%	0.1	0.0%	(5.7%)
Solar	3.7	0.0%	37.9	0.0%	934.9%
Battery	0.3	0.0%	0.2	0.0%	(37.7%)
Total	567,231.4	100.0%	582,633.3	100.0%	2.7%

Table 3-23 PJM capacity factor (By unit type (GWh)); January through September 2010 and 2011[16, 17] (New table)

	2010 (Jan-Sep)		2011 (Jan-Sep)	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.3	4.0%	0.2	1.3%
Combined Cycle	59,379.5	28.8%	74,151.5	46.7%
Combustion Turbine	6,987.2	3.8%	5,691.7	3.0%
Diesel	616.8	19.6%	542.5	16.7%
Diesel (Landfill gas)	501.9	40.4%	581.0	42.5%
Nuclear	192,379.3	93.3%	195,196.7	91.9%
Pumped Storage Hydro	6,246.5	17.4%	5,460.1	15.2%
Run of River Hydro	4,946.2	32.2%	5,919.8	38.6%
Solar	3.7	14.9%	37.9	12.7%
Steam	289,996.6	55.6%	287,127.5	52.2%
Wind	6,157.5	24.2%	7,924.5	27.2%
Total	567,215.4	49.6%	582,633.3	48.8%

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

16 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.

17 The capacity factor for solar units in 2010 contains a significantly smaller sample of units than 2011.

Planned Generation Additions

Table 3-24 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through September 30, 2011[18] (See 2010 SOM, Table 3-44)

	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 (Jan-Sep)	3,639

PJM Generation Queues

Table 3-25 Queue comparison (MW): September 30, 2011 vs. December 31, 2010 (See 2010 SOM, Table 3-44)

	MW in the Queue 2010	MW in the Queue 2011	Year-to-Year Change (MW)	Year-to-Year Change
2011	25,378	15,913	(9,466)	(37%)
2012	13,261	16,478	3,217	24%
2013	11,244	12,999	1,755	16%
2014	13,888	17,009	3,121	22%
2015	5,960	15,563	9,603	161%
2016	1,350	4,009	2,659	197%
2017	2,140	1,700	(440)	(21%)
2018	3,194	3,194	0	0%
Total	76,415	86,864	10,449	14%

Table 3-26 Capacity in PJM queues (MW): At September 30, 2011[19, 20] (See 2010 SOM, Table 3-46)

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	15,833	20,478
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	16,887	17,682
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	1,086	555	21,461	23,102
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,738	3,841
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	148	150	2,346	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	150	3,828	4,482
N Expired 31-Jan-05	1,377	2,143	173	6,713	10,407
O Expired 31-Jul-05	1,466	1,470	574	4,083	7,592
P Expired 31-Jan-06	513	2,625	655	4,908	8,701
Q Expired 31-Jul-06	1,759	1,384	2,778	8,693	14,614
R Expired 31-Jan-07	4,587	691	1,283	16,194	22,755
S Expired 31-Jul-07	2,357	2,618	925	14,993	20,893
T Expired 31-Jan-08	11,425	927	471	14,845	27,667
U Expired 31-Jan-09	6,295	222	815	26,116	33,447
V Expired 31-Jan-10	12,317	111	419	4,287	17,134
W Expired 31-Jan-11	16,275	10	617	7,605	24,507
X Expires 31-Jan-12	18,920	0	60	355	19,335
Total	77,310	30,020	9,624	218,358	335,311

18 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

19 The *2011 Quarterly State of the Market Report for PJM: January through September* contains all projects in the queue including reratings of existing generating units and energy only resources.

20 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Table 3-27 Average project queue times (days): At September 30, 2011 (See 2010 SOM, Table 3-47)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	812	656	0	4,420
In-Service	782	652	0	3,602
Suspended	2,307	897	704	4,103
Under Construction	1,214	841	0	4,370
Withdrawn	461	491	0	3,186

Distribution of Units in the Queues

Table 3-28 Capacity additions in active or under-construction queues by control zone (MW): At September 30, 2011 (See 2010 SOM, Table 3-48)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	1,255	762	9	0	0	797	665	0	2,191	5,680
AEP	4,325	0	21	170	0	143	2,416	0	14,136	21,210
AP	958	0	8	98	0	372	597	32	1,215	3,281
ATSI	268	72	22	0	0	14	135	0	1,047	1,558
BGE	0	0	29	0	1,640	0	132	0	0	1,801
ComEd	1,080	398	103	23	613	95	1,366	20	15,502	19,199
DAY	0	0	2	112	0	73	12	0	1,440	1,639
DLCO	0	0	0	0	91	0	0	0	0	91
Dominion	5,241	595	16	0	1,669	134	429	32	984	9,100
DPL	1,759	96	0	0	0	263	20	34	905	3,077
JCPL	1,995	27	30	0	0	1,178	0	0	0	3,230
Met-Ed	1,910	0	21	0	24	210	0	3	0	2,168
PECO	663	7	17	0	490	26	0	2	0	1,206
PENELEC	905	20	5	0	0	36	146	0	1,600	2,711
Pepco	2,309	0	6	0	0	10	0	0	0	2,325
PPL	1,354	13	10	3	1,600	144	33	20	420	3,597
PSEG	3,343	1,083	1	0	50	388	105	2	20	4,991
Total	27,365	3,073	301	406	6,177	3,883	6,055	145	39,459	86,864

Table 3-29 Capacity additions in active or under-construction queues by LDA (MW): At September 30, 2011[21] (See 2010 SOM, Table 3-49)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	9,015	1,975	57	0	540	2,652	790	38	3,116	18,183
SWMAAC	2,309	0	35	0	1,640	10	132	0	0	4,126
WMAAC	4,169	33	36	3	1,624	390	179	23	2,020	8,476
Non-MAAC	11,872	1,065	172	403	2,373	831	4,955	84	34,323	56,078
Total	27,365	3,073	301	406	6,177	3,883	6,055	145	39,459	86,864

21 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 3-30 Existing PJM capacity: At September 30, 2011[22] (By zone and unit type (MW)) (See 2010 SOM, Table 3-50)

	CC	CT	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	154	661	21	0	0	20	1,110	0	8	1,973
AEP	4,367	3,676	59	1,002	2,094	0	21,571	0	1,203	33,973
AP	1,129	1,180	36	80	0	0	8,451	27	663	11,566
ATSI	0	1,661	52	0	2,134	0	7,998	0	0	11,845
BGE	0	835	7	0	1,705	0	3,007	0	0	5,554
ComEd	1,763	7,178	86	0	10,421	0	6,790	0	1,945	28,183
DAY	0	1,369	48	0	0	1	4,368	0	0	5,785
DLCO	244	15	0	6	1,777	0	1,244	0	0	3,286
Dominion	3,435	3,761	161	3,589	3,558	0	8,283	0	0	22,787
DPL	1,125	1,773	96	0	0	0	1,825	0	0	4,819
External	974	690	0	66	439	0	6,117	0	185	8,471
JCPL	1,693	1,225	33	400	615	0	15	0	0	3,980
Met-Ed	2,041	416	42	20	805	0	844	0	0	4,167
PECO	2,644	836	7	1,642	4,541	3	1,706	1	0	11,379
PENELEC	0	344	39	513	0	0	6,834	0	555	8,284
Pepco	230	1,327	12	0	0	0	4,679	0	0	6,248
PPL	1,810	618	49	581	2,470	0	5,527	0	220	11,274
PSEG	2,960	2,863	5	5	3,493	47	2,447	0	0	11,820
Total	24,568	30,425	751	7,904	34,051	71	92,815	28	4,779	195,393

22 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-31 PJM capacity (MW) by age: at September 30, 2011 (See 2010 SOM, Table 3-51)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	18,490	15,587	430	11	0	71	1,864	28	4,768	41,250
11 to 20	4,657	6,323	89	48	0	0	4,936	0	10	16,062
21 to 30	980	1,162	37	3,382	16,517	0	6,920	0	0	28,998
31 to 40	244	4,251	43	105	16,053	0	33,782	0	0	54,479
41 to 50	198	3,103	148	2,915	1,482	0	26,650	0	0	34,495
51 to 60	0	0	4	379	0	0	16,466	0	0	16,849
61 to 70	0	0	0	0	0	0	2,047	0	0	2,047
71 to 80	0	0	0	344	0	0	95	0	0	439
81 to 90	0	0	0	488	0	0	54	0	0	542
91 to 100	0	0	0	194	0	0	0	0	0	194
101 and over	0	0	0	37	0	0	0	0	0	37
Total	24,568	30,425	751	7,904	34,051	71	92,815	28	4,779	195,393

Table 3-32 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[23] (See 2010 SOM, Table 3-52)

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%	8,576	25.2%	9,015	17,392	39.0%
	Combustion Turbine	1,375	16.9%	7,358	21.7%	1,975	7,958	17.8%
	Diesel	53	0.7%	162	0.5%	57	166	0.4%
	Hydroelectric	2,042	25.1%	2,047	6.0%	0	5	0.0%
	Nuclear	615	7.6%	8,648	25.5%	540	9,188	20.6%
	Solar	0	0.0%	70	0.2%	2,652	2,722	6.1%
	Steam	3,841	47.3%	7,102	20.9%	790	4,051	9.1%
	Storage	0	0.0%	1	0.0%	38	39	0.1%
	Wind	0	0.0%	8	0.0%	3,116	3,124	7.0%
	EMAAC Total	8,124	100.0%	33,972	100.0%	18,183	44,645	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	2,309	2,539	22.4%
	Combustion Turbine	761	16.5%	2,162	18.3%	0	1,400	12.4%
	Diesel	0	0.0%	19	0.2%	35	54	0.5%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	29.5%
	Solar	0	0.0%	0	0.0%	10	10	0.1%

23 Percentages shown in Table 3-32 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 3-32 continued on next page.

Table 3-32 continued from previous page.

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
	Steam	3,840	83.5%	7,686	65.1%	132	3,978	35.1%
	SWMAAC Total	4,601	100.0%	11,801	100.0%	4,126	11,327	100.0%
WMAAC	Combined Cycle	0	0.0%	3,851	16.2%	4,169	8,020	50.0%
	Combustion Turbine	312	3.8%	1,377	5.8%	33	1,098	6.8%
	Diesel	46	0.6%	129	0.5%	36	120	0.7%
	Hydroelectric	887	10.9%	1,113	4.7%	3	229	1.4%
	Nuclear	0	0.0%	3,275	13.8%	1,624	4,899	30.5%
	Solar	0	0.0%	0	0.0%	390	390	2.4%
	Steam	6,887	84.7%	13,205	55.7%	179	6,496	40.5%
	Storage	0	0.0%	0	0.0%	23	23	0.1%
	Wind	0	0.0%	775	3.3%	2,020	2,795	17.4%
	WMAAC Total	8,132	100.0%	23,725	100.0%	8,476	16,049	100.0%
Non-MAAC	Combined Cycle	0	0.0%	11,911	9.5%	11,872	23,783	16.0%
	Combustion Turbine	655	1.9%	19,529	15.5%	1,065	19,939	13.5%
	Diesel	53	0.2%	441	0.4%	172	560	0.4%
	Hydroelectric	1,429	4.2%	4,744	3.8%	403	3,718	2.5%
	Nuclear	867	2.6%	20,423	16.2%	2,373	21,929	14.8%
	Solar	0	0.0%	1	0.0%	831	832	0.6%
	Steam	30,744	91.1%	64,822	51.5%	4,955	39,033	26.3%
	Storage	0	0.0%	27	0.0%	84	111	0.1%
	Wind	0	0.0%	3,996	3.2%	34,323	38,320	25.9%
	Non-MAAC Total	33,747	100.0%	125,895	100.0%	56,078	148,226	100.0%
All Areas	Total	54,605		195,393		86,864	220,247	

Environmental Impact and Renewables

Characteristics of Wind Units

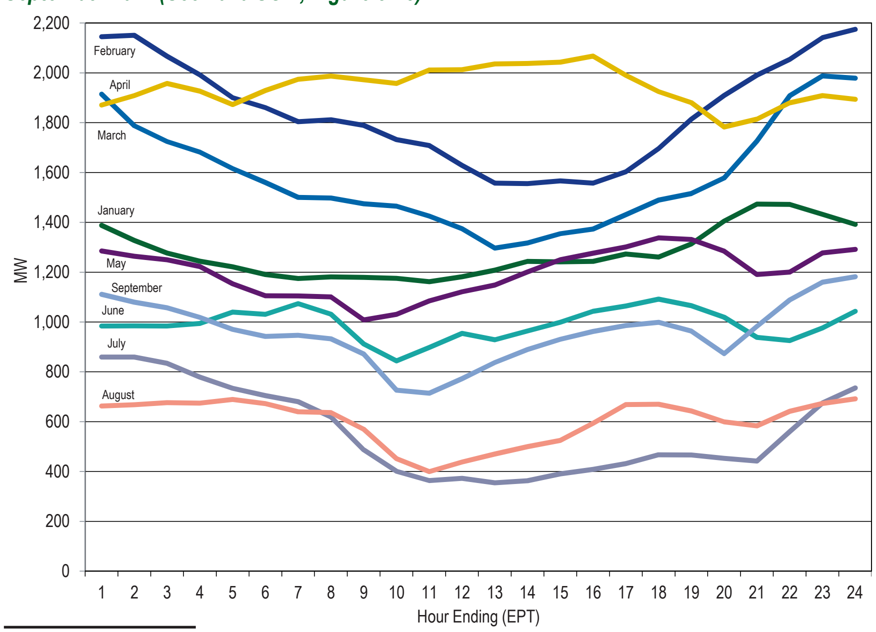
Table 3-33 Capacity factor[24] of wind units in PJM, January through September 2011 (See 2010 SOM, Table 3-53)

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Total Hours	Installed Capacity (MW)
Energy-Only Resource	23.7%	NA	85,859	849
Capacity Resource	27.7%	169.2%	264,800	3,957
All Units	27.2%	169.2%	350,659	4,806

Table 3-34 Wind resources in real time offering at a negative price in PJM, January through September 2011 (See 2010 SOM, Table 3-54)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	908.0	1,987	2.53%
All Wind	2,136.4	4,071	5.18%

Figure 3-7 Average hourly real-time generation of wind units in PJM, January through September 2011 (See 2010 SOM, Figure 3-13)



24 Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

Table 3-35 Capacity factor of wind units in PJM by month, 2010 and 2011[25] (See 2010 SOM, Table 3-55)

	2010		2011	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	971,942.0	35.9%	950,441.9	29.7%
February	736,663.6	28.9%	1,237,813.0	42.4%
March	853,590.0	30.3%	1,175,567.0	36.4%
April	1,001,447.6	36.6%	1,399,217.0	44.7%
May	730,087.9	25.9%	893,485.1	27.6%
June	492,344.0	17.7%	713,713.8	21.9%
July	396,754.7	13.7%	416,695.8	12.1%
August	344,015.5	11.6%	447,575.2	13.0%
September	733,193.7	23.0%	689,962.6	20.7%
October	1,042,735.7	31.1%		
November	1,127,306.0	34.0%		
December	1,159,478.3	33.8%		
Annual	9,589,559.0	27.4%	7,924,471.5	27.2%

Table 3-36 Table 3-16 Peak and off-peak seasonal capacity factor, average wind generation (MWh), and PJM load (MWh): January through September 2011 (See 2010 SOM, Table 3-56)

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	34.1%	43.1%	19.1%		26.5%
	Average Wind Generation	1,474.1	2,003.5	869.3		1,180.8
	Average Load	86,939.1	75,551.5	99,674.0		92,790.6
Off-Peak	Capacity Factor	37.7%	46.1%	18.8%		27.7%
	Average Wind Generation	1,633.8	1,874.6	853.7		1,235.1
	Average Load	75,243.8	62,156.7	78,079.9		75,397.1

25 Capacity factor shown in Table 3-35 is based on all hours in January through September, 2011.

Figure 3-8 Average hourly day-ahead generation of wind units in PJM, January through September 2011 (See 2010 SOM, Figure 3-14)

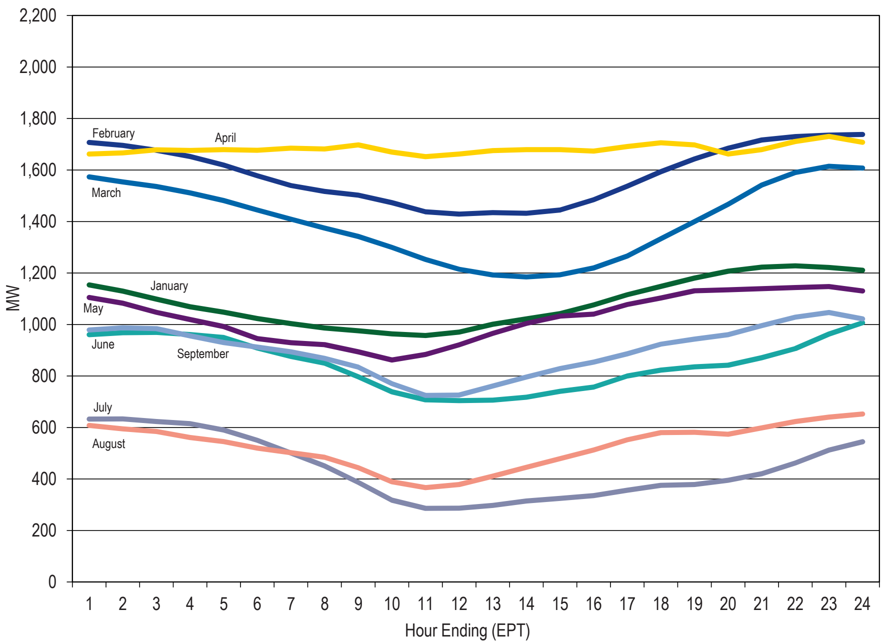
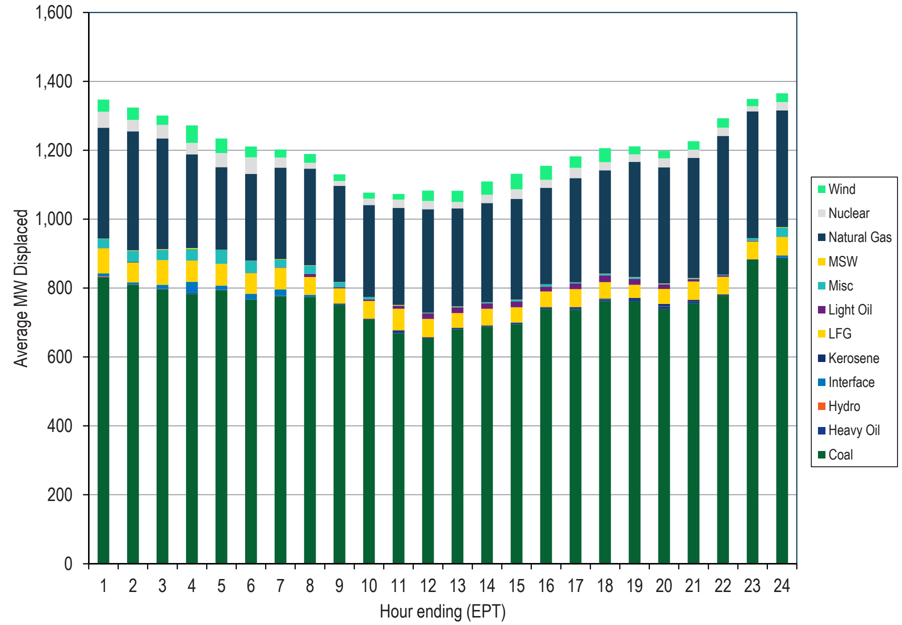


Figure 3-9 Marginal fuel at time of wind generation in PJM, January through September 2011 (See 2010 SOM, Figure 3-15)



Environmental Regulatory Impacts

Emission Allowances Trading

Figure 3-10 Spot monthly average emission price comparison: 2010 and 2011 (See 2010 SOM, Figure 3-16)

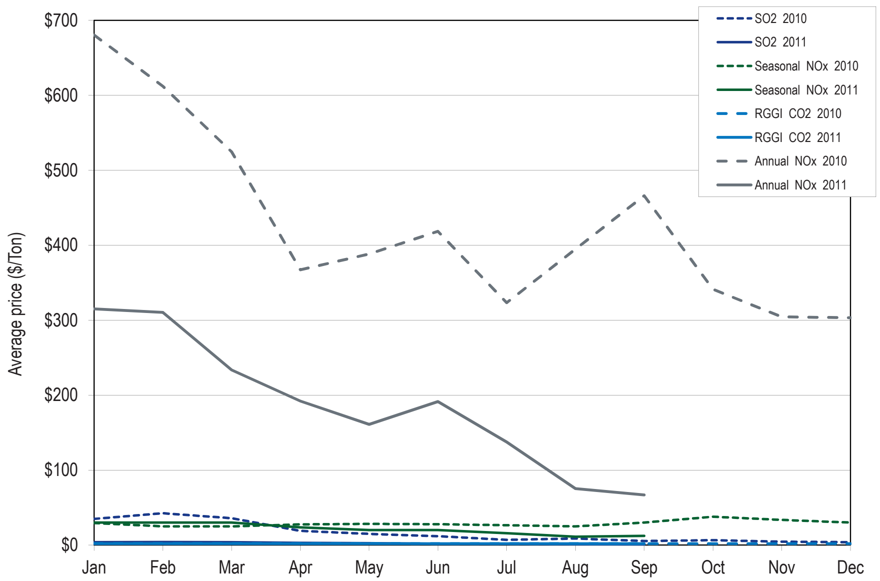


Table 3-37 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2010 SOM, Table 3-57)[26]

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

Emission Controlled Capacity in the PJM Region

Table 3-38 SO_2 emission controls (FGD) by unit type (MW), as of September 30, 2011 (See 2010 SOM, Table 3-58)

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	51,991.2	29,924.6	81,915.8	63.5%
Combined Cycle	0.0	24,520.7	24,520.7	0.0%
Combustion Turbine	0.0	30,320.8	30,320.8	0.0%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	0.0	10,000.5	10,000.5	0.0%
Total	51,991.2	95,133.1	147,124.3	35.3%

26 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed October 1, 2011).

 www.monitoringanalytics.com

Table 3-39 NO_x emission controls by unit type (MW), as of September 30, 2011 (See 2010 SOM, Table 3-59)

	NO_x Controlled	No NOx Controls	Total	Percent Controlled
Coal Steam	79,293.0	2,622.8	81,915.8	96.8%
Combined Cycle	24,329.6	191.1	24,520.7	99.2%
Combustion Turbine	24,936.4	5,384.4	30,320.8	82.2%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	5,012.7	4,987.8	10,000.5	50.1%
Total	133,571.7	13,552.6	147,124.3	90.8%

Table 3-40 Particulate emission controls by unit type (MW), as of September 30, 2011 (See 2010 SOM, Table 3-60)

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	80,281.8	1,634.0	81,915.8	98.0%
Combined Cycle	0.0	24,520.7	24,520.7	0.0%
Combustion Turbine	0.0	30,320.8	30,320.8	0.0%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	3,047.0	6,953.5	10,000.5	30.5%
Total	83,328.8	63,795.5	147,124.3	56.6%

CSAPR and HEDD Limits

Table 3-41 2012 and 2014 assurance levels for SO_2[27], NO_x, and O_3 season NO_x[28] emissions (New table)

	SO_2		NO_x		O3 Season NO_x	
	2012 Assurance Level	2014 Assurance Level	2012 Assurance Level	2014 Assurance Level	2012 Assurance Level	2014 Assurance Level
Illinois	277,169	146,465	56,489	56,489	25,662	25,662
Indiana	336,800	190,111	129,477	127,940	56,720	55,872
Kentucky	274,541	125,415	100,401	91,141	43,762	39,536
Maryland	35,542	33,280	19,627	19,557	8,687	8,687
Michigan	270,578	169,914	77,197	74,387	31,160	29,920
New Jersey	9,051	6,577	9,069	8,706	4,809	4,328
North Carolina	161,520	67,992	59,693	49,033	26,823	22,331
Ohio	366,071	161,751	109,390	103,242	48,476	45,728
Pennsylvania	328,808	132,185	141,583	140,649	63,163	62,814
Tennessee	174,817	69,423	42,130	22,818	18,039	9,699
Virginia	83,568	41,367	39,226	39,226	17,487	17,487
West Virginia	172,485	89,288	70,177	64,407	30,592	28,182

Table 3-42 HEDD maximum NO_x emission rates[29] (New table)

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

27 Annual NOX assurance levels for Michigan and Annual NO_x and SO_2 and Seasonal NOX for New Jersey are as adjusted in the Proposed Revised CSAPR II, as set forth in the Technical Revisions to State Budgets and New Unit Set-Asides, Docket No. EPA-HQ-2009-0491 (October 2011) at 5 (Table 1.208.b) & 38 (Table 10.h).

28 CSPAR at 48269–70 (Tables VI.F-1, F-2 & F-3); Proposed Revised CSAPR at 40666 (Table 1.C-2).

29 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.

Renewable Portfolio Standards

Table 3-43 Renewable standards of PJM jurisdictions to 2021[30,31] (See 2010 SOM, Table 3-61)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	7.00%	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%
Indiana	No Standard										
Illinois	6.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%
Kentucky	No Standard										
Maryland	7.50%	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%
Michigan		<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	8.30%	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%
North Carolina	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%
Ohio	1.00%	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%
Pennsylvania	9.20%	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Washington, D.C.	6.54%	7.57%	9.10%	10.63%	12.17%	13.71%	15.25%	16.80%	18.35%	20.40%	20.40%
West Virginia					10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%

30 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.
31 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.

Table 3-44 Solar renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-62)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	0.20%	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%
Indiana	No Standard										
Illinois		0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%
Kentucky	No Standard										
Maryland	0.05%	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%	1.85%
Michigan	No Solar Standard										
New Jersey	0.31%	0.39%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%	2.12%
North Carolina	0.07%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
Ohio	0.03%	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%
Pennsylvania	0.02%	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.04%	0.07%	0.10%	0.13%	0.17%	0.21%	0.25%	0.30%	0.35%	0.40%	0.40%
West Virginia	No Solar Standard										

Table 3-45 Additional renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-63)

Jurisdiction		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Illinois	Wind Requirement	3.75%	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%	2.50%	2.50%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)		306	442	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518
North Carolina	Swine Waste			0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)			170	700	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	4.20%	6.20%	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%

Table 3-46 Renewable alternative compliance payments in PJM jurisdictions: 2011 (See 2010 SOM, Table 3-64)

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	No standard		
Illinois	$12.73		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$675.00
North Carolina	No specific penalties		
Ohio	$45.00		$400.00
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 3-47 Renewable generation by jurisdiction and renewable resource type (GWh): January through September 2011 (See 2010 SOM, Table 3-65)

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	44.1	0.0	0.0	0.0	0.0	0.0	0.0	44.1	88.1
Indiana	0.0	0.0	32.1	0.0	0.0	0.0	1,856.4	1,888.5	1,888.5
Illinois	111.0	0.0	0.0	0.0	7.6	0.0	3,813.7	3,924.7	3,932.4
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	71.8	0.0	1,728.3	0.0	690.4	0.0	210.9	2,011.0	2,701.3
Michigan	20.9	0.0	46.6	0.0	0.0	0.0	0.0	67.5	67.5
New Jersey	233.8	456.3	20.5	34.1	1,056.0	0.0	6.8	295.1	1,807.5
North Carolina	0.0	0.0	289.9	0.0	0.0	0.0	0.0	289.9	289.9
Ohio	72.6	0.0	92.9	1.1	0.0	0.0	52.1	218.7	218.7
Pennsylvania	664.2	1,307.5	2,401.2	2.7	1,322.0	8,373.5	1,257.8	4,326.0	15,328.9
Tennessee	0.0	0.0	0.0	0.0	252.0	0.0	0.0	0.0	252.0
Virginia	134.1	3,696.2	541.1	0.0	926.8	0.0	0.0	675.3	5,298.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	3.4	0.0	767.1	0.0	0.0	786.3	726.9	1,497.4	2,283.8
Total	1,356.0	5,460.1	5,919.8	37.9	4,254.8	9,159.8	7,924.5	15,238.2	34,112.8

Table 3-48 PJM renewable capacity by jurisdiction (MW), on September 30, 2011 (See 2010 SOM, Table 3-66)

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	15.0	0.0	0.0	0.0	0.0	0.0	0.0	1,858.4
Illinois	0.0	64.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	1,944.9	2,029.8
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,053.2	1,061.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Maryland	0.0	24.5	129.0	66.0	0.0	1,162.0	0.0	109.0	0.0	120.0	1,610.5
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	67.3	191.1	0.0	7.5	756.4
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
Ohio	3,028.7	25.8	0.0	18.0	.	112.0	1.1	0.0	0.0	150.0	3,335.6
Pennsylvania	0.0	215.5	2,327.0	0.0	2,575.0	672.6	3.0	263.0	1,473.9	790.0	8,320.0
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	108.5	80.0	16.9	3,588.0	457.1	0.0	215.0	0.0	0.0	4,465.5
West Virginia	301.0	2.0	0.0	0.0	0.0	239.6	0.0	0.0	130.0	528.1	1,200.7
PJM Total	3,329.7	539.6	4,371.3	115.9	6,563.0	2,983.3	71.4	943.1	1,603.9	4,778.7	25,299.9

Table 3-49 Renewable capacity by jurisdiction, non-PJM units registered in GATS[32,33] (MW), on September 30, 2011 (See 2010 SOM, Table 3-67)

Jurisdiction	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	21.1	0.0	0.1	21.2
Illinois	4.0	97.8	0.0	0.0	0.0	10.6	0.0	302.5	415.0
Indiana	0.0	32.2	0.0	679.1	0.0	0.4	0.0	0.0	711.7
Kentucky	2.0	16.0	0.0	0.0	0.0	0.3	88.0	0.0	106.4
Maryland	0.0	7.0	0.0	0.0	0.0	29.8	0.0	0.0	36.8
Michigan	0.0	1.6	0.0	0.0	0.0	0.1	0.0	0.0	1.7
Minnesota	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	146.0	146.0
New Jersey	0.0	39.9	0.0	0.0	23.3	355.7	0.0	0.2	419.1
New York	141.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	142.1
North Carolina	225.0	0.0	0.0	0.0	0.0	2.1	0.0	0.0	227.1
Ohio	1.0	37.3	52.6	45.0	0.0	25.8	109.3	10.3	281.3
Pennsylvania	0.2	5.4	4.8	85.5	0.3	102.1	0.0	3.2	201.5
Virginia	12.5	14.8	0.0	0.0	0.0	3.9	318.1	0.0	349.4
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	2.4
West Virginia	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.4
Wisconsin	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Total	395.5	252.1	57.4	809.6	23.6	555.5	560.0	462.4	3,116.0

32 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.
33 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed October 01, 2011).

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 current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[34] 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 be the result of appropriate scarcity pricing rather than market power.

The energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. This provides the rationale for administrative scarcity pricing mechanisms such as PJM's Reliability Pricing Model (RPM) market for capacity and its administrative scarcity pricing mechanism in the energy market. Scarcity revenues to generation owners can come from a combination of energy and capacity markets or they can come entirely from capacity markets.

PJM's current administrative scarcity pricing mechanism is designed to recognize real-time scarcity in the Energy Market and increase prices to reflect the scarcity conditions. Under the current PJM rules, administrative scarcity pricing results when PJM takes identified emergency actions and is based on the highest offer of an operating unit.

There is an issue with how the capacity market rules interact with the current scarcity pricing rules. While the capacity market rules create incentives to make capacity available during the highest load periods of the year, this capacity does not have to be made available as non-emergency MW. When scarcity conditions are a possibility, as in the case when PJM declares a Maximum Emergency Generation Alert or a Hot Weather Alert, PJM's current scarcity rules provide an incentive for some capacity MW to be made available as emergency MW, as the loading of maximum emergency generation for a Scarcity Constraint triggers scarcity pricing under the current rules. The tariff limits the classification of MW as emergency under scarcity conditions unless they meet four defined criteria, but this is a hard rule to enforce in practice.[35] The MMU recommends that the rules be clarified.

34 See *2011 Quarterly State of the Market Report for PJM: January through September*, Section 2, "Energy Market, Part I," at Figure 2-1, "Average PJM aggregate supply curves: July through September 2010 and 2011."

35 See PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations. See PJM. "Manual 13: Emergency Operations," Revision: 44 (Effective May 26, 2011), p. 68.

High-Load Events: January through September 2011

There were no scarcity pricing events in the January through September 2011 period under PJM's current emergency action based scarcity pricing rules.

In general, participant behavior in the summer of 2011 was consistent with the market incentives created by the Capacity and Energy Market. During the declared Hot Weather Alerts in 2011, declared outage MW were lower than the average declared outage MW in the May through August period. Maximum emergency generation declarations during maximum emergency generation periods were also lower than the monthly averages in the period. However, energy was produced from declared emergency segments during a number of Hot Weather Alert days, when energy prices were below $500 per MWh and in the absence of PJM specific instructions to load the maximum emergency generation. This behavior suggests that some emergency MW segments were incorrectly classified.

There were a total of 35 high-load hours in 2011.[36] There were eleven days with high load hours in June, July and July of 2011: two in June, six in July and three in August. There were eight high load hours in June, sixteen in July and eleven in August. In the May through September period, PJM declared twenty one Hot Weather Alerts.[37]

36 A high-load hour is defined to exist when hourly demand, including the day-ahead operating reserve target, equals 96 percent or more of total, within-30 minute supply in the absence of non market administrative intervention, on an hourly integrated basis. See PJM "Manual 13: Emergency Operations", Revision 44. Effective Date May 26, 2011. p 11.

37 "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."

Operating Reserve[38]

Credit and Charge Results

Overall Results

Table 3-50 Monthly operating reserve charges: Calendar years 2010 and 2011 (See SOM 2010, Table 3-72)

	2010 Charges				2011 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$10,281,351	$50,022	$40,472,496	$50,803,869	$12,373,099	$110,095	$49,241,974	$61,725,168
Feb	$11,425,494	$14,715	$22,346,529	$33,786,738	$8,940,203	$139,287	$26,504,113	$35,583,603
Mar	$8,836,886	$122,817	$16,823,288	$25,782,991	$6,837,719	$66,032	$23,817,025	$30,720,775
Apr	$7,633,141	$93,253	$22,870,495	$30,596,889	$4,405,102	$13,011	$18,454,339	$22,872,452
May	$5,127,307	$131,600	$39,144,404	$44,403,311	$7,064,934	$39,417	$45,834,527	$52,938,878
Jun	$3,511,264	$33,923	$56,989,229	$60,534,415	$8,303,391	$9,056	$62,117,583	$70,430,030
Jul	$4,601,788	$88,136	$63,190,853	$67,880,778	$4,993,311	$238,127	$106,125,466	$111,356,905
Aug	$3,622,670	$66,535	$41,690,612	$45,379,817	$8,360,392	$104,982	$55,277,638	$63,743,012
Sep	$8,433,892	$27,971	$40,637,086	$49,098,949	$6,249,240	$40,878	$36,357,847	$42,647,965
Oct	$7,719,744	$1,543	$30,433,986	$38,155,273				
Nov	$6,556,715	$29,674	$20,020,310	$26,606,698				
Dec	$12,951,879	$59,954	$83,021,125	$96,032,958				
Total	$63,473,794	$628,972	$344,164,993	$408,267,759	$67,527,391	$760,886	$423,730,511	$492,018,787
Share of Annual Charges	15.5%	0.2%	84.3%	100.0%	13.7%	0.2%	86.1%	100.0%

38 See the *2010 State of the Market Report for PJM,* Volume II, Section 3, "Energy Market, Part 2", Table 3-68 *Operating reserve credit and charges* and Table 3-69 *Operating reserve deviations* for details regarding operating reserve structure.

Table 3-51 Regional balancing operating reserve charges allocation: January through September 2011[39] (See SOM 2010, Table 3-73)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$45,657,166 9.5%	$1,851,929 0.4%	$47,509,095 9.9%	$79,832,680 16.6%	$23,993,384 5.0%	$206,001,417 42.9%	$309,827,481 64.5%	$357,336,576 74.4%
East	$9,755,946 2.0%	$583,122 0.1%	$10,339,068 2.2%	$23,528,097 4.9%	$6,123,664 1.3%	$59,588,642 12.4%	$89,240,403 18.6%	$99,579,471 20.7%
West	$16,011,130 3.3%	$874,280 0.2%	$16,885,410 3.5%	$3,418,605 0.7%	$1,224,749 0.3%	$2,033,089 0.4%	$6,676,443 1.4%	$23,561,853 4.9%
Total	$71,424,242 14.9%	$3,309,330 0.7%	$74,733,573 15.6%	$106,779,383 22.2%	$31,341,796 6.5%	$267,623,148 55.7%	$405,744,328 84.4%	$480,477,900 100%

Deviations

Allocation

Table 3-52 Monthly balancing operating reserve deviations (MWh): Calendar years 2010 and 2011 (See SOM 2010, Table 3-74)

	2010 Deviations				2011 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,439,465	5,707,965	2,698,568	17,845,998	9,798,230	3,261,409	25,640,990	38,700,629
Feb	7,675,656	5,332,236	2,456,048	15,463,940	7,196,554	2,809,384	22,571,322	32,577,260
Mar	8,101,950	5,138,264	2,264,951	15,505,165	7,510,358	2,467,175	23,370,795	33,348,329
Apr	7,006,983	4,668,407	2,132,045	13,807,435	6,624,265	2,028,227	21,698,434	30,350,926
May	9,004,034	4,228,004	2,416,103	15,648,141	7,213,247	2,450,164	23,189,595	32,853,005
Jun	10,936,989	3,964,478	3,174,230	18,075,697	10,155,922	2,865,616	20,822,919	33,844,457
Jul	10,928,408	3,847,011	3,412,498	18,187,917	10,170,858	2,690,836	21,948,613	34,810,307
Aug	9,747,045	3,417,328	3,188,437	16,352,810	8,566,032	2,057,281	18,493,882	29,117,195
Sep	9,480,237	3,587,356	2,524,213	15,591,806	8,829,765	2,198,723	17,992,916	29,021,403
Oct	7,170,712	2,913,554	2,368,303	12,452,569				
Nov	7,606,971	2,860,054	2,485,153	12,952,178				
Dec	10,069,627	4,027,236	3,513,489	17,610,352				
Total	107,168,077	49,691,893	32,634,038	189,494,008	76,065,232	22,828,814	195,729,467	294,623,512
Share of Annual Deviations	56.6%	26.2%	17.2%	100.0%	25.8%	7.7%	66.4%	100.0%

39 The total charges shown in Table 3-52 do not equal the total balancing charges shown in Table 3-50 because the totals in Table 3-50 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-52 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while lost opportunity cost, cancellation, and local charges are allocated on an RTO basis, based on demand, supply, and generator deviations.

Table 3-53 R egional operating reserve charges determinants (MWh): January through September 2011 (See SOM 2010, Table 3-75)

	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	Total
RTO	548,529,196	23,853,706	572,382,902	76,065,232	22,828,814	195,729,467	294,623,512	867,006,414
East	287,309,142	10,851,861	298,161,003	45,446,676	12,347,835	146,947,851	204,742,363	502,903,365
West	261,220,055	13,001,845	274,221,900	30,307,989	10,370,567	20,036,381	60,714,937	334,936,836

Operating Reserve Credits by Category

Figure 3-11 Operating reserve credits: January through September 2011 (See SOM 2010, Figure 3-22)

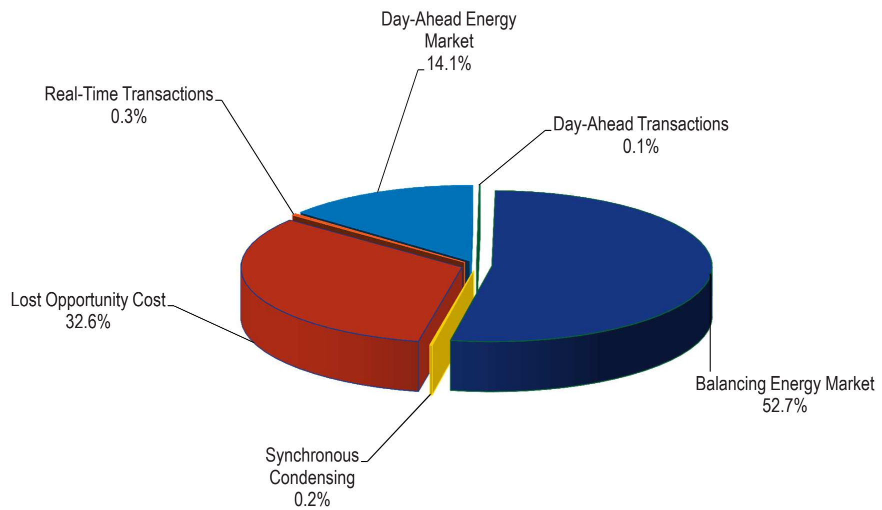


Table 3-54 Operating reserve credits by month (By operating reserve market): January through September 2011[40] (See SOM 2010, Table 3-79)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$12,352,611	$20,488	$110,095	$43,536,900	$473,239	$2,946,513	$59,439,847
Feb	$8,844,162	$96,041	$139,287	$22,920,110	$378,056	$3,205,948	$35,583,604
Mar	$6,830,696	$7,024	$66,032	$15,312,266	$421,862	$7,091,141	$29,729,020
Apr	$4,395,461	$9,641	$13,011	$11,008,300	$215,816	$7,230,224	$22,872,452
May	$7,057,377	$7,557	$39,417	$22,772,231	$13,365	$20,364,971	$50,254,918
Jun	$8,158,879	$144,512	$9,056	$31,864,011	$20,077	$27,996,648	$68,193,183
Jul	$4,972,654	$20,657	$238,127	$56,725,590	$1,068	$45,972,367	$107,930,463
Aug	$8,355,563	$4,828	$104,982	$29,638,014	$4,774	$24,131,500	$62,239,661
Sep	$6,249,124	$116	$40,878	$18,099,540	$40,005	$16,897,975	$41,327,639
Oct							
Nov							
Dec							
Total	$67,216,527	$310,864	$760,885	$251,876,963	$1,568,263	$155,837,286	$477,570,788
Share of Credits	14.1%	0.1%	0.2%	52.7%	0.3%	32.6%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-55 Operating reserve credits by unit types (By operating reserve market): January through September 2011 (See SOM 2010, Table 3-80)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	29.0%	0.0%	67.8%	3.2%	$92,661,071
Combustion Turbine	2.1%	0.4%	34.8%	62.6%	$186,099,392
Diesel	2.4%	0.0%	82.9%	14.7%	$299,174
Hydro	47.7%	0.0%	52.3%	0.0%	$252,916
Landfill	0.0%	0.0%	0.0%	100.0%	$16,217,096
Nuclear	0.0%	0.0%	0.0%	100.0%	$291,748
Steam	21.2%	0.0%	70.9%	7.9%	$167,676,815
Wind Farm	0.0%	0.0%	99.8%	0.2%	$3,439,734

40 Credits may not equal charges due to adjustments made by PJM Settlements that are only reflected on participants' final bills.

Table 3-56 Credits by operating reserve market (By unit type): January through September 2011 (See SOM 2010, Table 3-81)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	40.4%	0.0%	25.1%	2.0%
Combustion Turbine	5.9%	100.0%	25.9%	78.0%
Diesel	0.0%	0.0%	0.1%	0.0%
Hydro	0.2%	0.0%	0.1%	0.0%
Landfill	0.0%	0.0%	0.0%	10.9%
Nuclear	0.0%	0.0%	0.0%	0.2%
Steam	53.5%	0.0%	47.5%	8.9%
Wind Farm	0.0%	0.0%	1.4%	0.0%
Total	$66,473,554	$760,885	$250,324,547	$149,378,961

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-57 Regional balancing operating reserve credits: January through September 2011 (See SOM 2010, Table 3-86)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$47,509,095	$309,827,481	$357,336,576
East	$10,339,068	$89,240,403	$99,579,471
West	$16,885,410	$6,676,443	$23,561,853
Total	$74,733,573	$405,744,328	$480,477,900

Table 3-58 Total deviations: January through September 2011 (See SOM 2010, Table 3-87)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	76,065,232	22,828,814	195,729,467	294,623,512

Table 3-59 Actual regional credits, charges, rates and charge allocation (MWh): January through September 2011 (See SOM 2010, Table 3-89)

	Reliability Charges				Deviation Charges				
	Reliability Credits ($)	RT Load and Exports (MWh)	Reliability Rate ($/MWh)	Reliability Charges ($)	Deviation Credits ($)	Deviations (MWh)	Deviation Rate ($/MWh)	Deviation Charges ($)	Total Charges ($)
RTO	$47,509,095	572,382,903	0.083	$47,509,095	$309,827,481	294,623,512	1.052	$309,827,481	$357,336,576
East	$10,339,068	298,161,003	0.035	$10,339,068	$89,240,403	204,742,363	0.436	$89,240,403	$99,579,471
West	$16,885,410	274,221,900	0.062	$16,885,410	$6,676,443	60,714,937	0.110	$6,676,443	$23,561,853
Total	$74,733,573	572,382,903	NA	$74,733,573	$405,744,328	294,623,512	NA	$405,744,328	$480,477,900

Impact on Decrement Bids and Incremental Offers

Table 3-60 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh[41]): Calendar years 2010 and 2011 (See SOM 2010, Table 3-91)

	2010				2011			
Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	8,291,432	13,029,516	2,463,852	3,452,047	6,054,214	8,284,810	1,548,295	3,162,842
Feb	8,323,844	11,828,781	2,004,162	2,234,045	5,732,202	7,440,032	1,376,811	2,271,323
Mar	8,032,429	11,159,303	2,150,898	2,594,826	5,372,006	7,753,370	1,152,805	2,548,787
Apr	7,568,471	9,989,951	2,214,314	2,066,270	5,200,154	7,351,597	957,164	2,050,911
May	8,306,597	11,573,314	2,250,271	3,437,786	5,537,880	7,609,897	1,174,272	2,217,049
Jun	8,304,139	12,735,819	2,223,204	4,058,044	6,367,269	8,938,210	1,200,432	2,709,247
Jul	8,389,094	12,813,573	1,840,017	3,503,722	6,393,392	9,072,394	1,120,299	2,734,062
Aug	7,862,123	11,648,289	1,465,333	2,676,901	5,622,097	8,184,829	909,703	2,007,437
Sep	8,188,967	11,532,284	2,103,152	3,105,498	5,287,621	8,950,589	1,157,069	3,242,434
Oct	7,777,616	10,423,935	1,564,871	2,163,717				
Nov	8,027,852	11,041,950	1,408,786	2,467,942				
Dec	9,416,187	12,320,592	1,920,956	3,451,929				
Total	98,488,750	140,097,307	23,609,817	35,212,727	51,566,835	73,585,727	10,596,850	22,944,092

41 Adjusted deviations refer to increment offers and decrement bids that were net out by real-time imports, exports, transactions, generation, or load.

Issues in Operating Reserves

Concentration of Operating Reserve Credits

Table 3-61 Unit operating reserve credits (By zone): January through September 2011 (See SOM 2010, Table 3-100)

Zone	Day Ahead Generator Credit	Synchronous Condensing Credit	Balancing Generator Credit	Lost Opportunity Cost Credit	Total Operating Reserve Credits	Percent of Total Operating Reserve Credits
AECO	$409,727.39	$0.00	$4,430,442.94	$4,027,145.84	$8,867,316.17	1.9%
AEP	$2,388,192.09	$368.22	$33,790,330.36	$11,789,492.34	$47,968,383.01	10.1%
AP	$1,689,215.05	$0.00	$7,173,509.45	$11,376,236.71	$20,238,961.21	4.3%
ATSI	$686,850.33	$0.00	$801,390.25	$6,360,519.56	$7,848,760.14	1.6%
BGE	$8,440,411.63	$0.00	$9,647,240.77	$697,002.52	$18,784,654.92	3.9%
ComEd	$1,093,871.37	$0.00	$6,370,679.99	$16,562,749.55	$24,027,300.91	5.1%
DAY	$175,225.95	$0.00	$841,482.18	$713,149.48	$1,729,857.61	0.4%
Dominion	$5,595,544.83	$0.00	$43,697,947.29	$87,375,575.12	$136,669,067.24	28.7%
DLCO	$304,052.68	$0.00	$2,446,671.01	$5,453.81	$2,756,177.50	0.6%
DPL	$1,733,225.40	$0.00	$14,609,449.62	$4,480,898.32	$20,823,573.34	4.4%
JCPL	$1,563,596.70	$0.00	$6,339,948.63	$1,746,302.20	$9,649,847.53	2.0%
Met-Ed	$231,931.10	$0.00	$2,701,605.30	$456,040.87	$3,389,577.27	0.7%
PECO	$601,993.21	$4,691.56	$7,402,864.20	$394,817.43	$8,404,366.40	1.8%
PENELEC	$430,190.07	$0.00	$3,201,480.17	$3,592,925.25	$7,224,595.49	1.5%
Pepco	$3,531,212.34	$0.00	$38,825,588.16	$1,234,641.44	$43,591,441.94	9.2%
PPL	$653,774.02	$0.00	$7,690,558.74	$1,604,047.85	$9,948,380.61	2.1%
PSEG	$37,687,512.46	$755,825.69	$61,905,774.03	$3,420,287.89	$103,769,400.07	21.8%
External	$0.00	$0.00	$0.00	$0.00	$0.00	0.0%
Total	$67,216,526.62	$760,885.47	$251,876,963.09	$155,837,286.18	$475,691,661.36	100.0%

Table 3-62 Top 10 units and organizations receiving total operating reserve credits: January through September 2011 (See SOM 2010, Table 3-101)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$30,032,491	6.3%	6.3%	$107,930,853	22.7%	22.7%
2	$24,125,705	5.1%	11.4%	$102,987,596	21.7%	44.3%
3	$20,217,005	4.3%	15.6%	$31,705,644	6.7%	51.0%
4	$18,083,292	3.8%	19.4%	$29,565,668	6.2%	57.2%
5	$12,889,230	2.7%	22.1%	$25,977,869	5.5%	62.7%
6	$8,872,694	1.9%	24.0%	$24,271,927	5.1%	67.8%
7	$7,244,337	1.5%	25.5%	$18,251,590	3.8%	71.6%
8	$6,981,948	1.5%	27.0%	$17,559,600	3.7%	75.3%
9	$6,748,554	1.4%	28.4%	$16,253,488	3.4%	78.7%
10	$6,228,987	1.3%	29.7%	$14,688,384	3.1%	81.8%

Table 3-63 Top 10 units and organizations receiving day-ahead generator credits: January through September 2011 (See SOM 2010, Table 3-102)

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$13,407,979	19.9%	19.9%	$37,543,343	55.9%	55.9%
2	$12,897,002	19.2%	39.1%	$9,033,617	13.4%	69.3%
3	$6,149,535	9.1%	48.3%	$5,004,091	7.4%	76.7%
4	$3,373,898	5.0%	53.3%	$4,717,423	7.0%	83.8%
5	$2,965,345	4.4%	57.7%	$1,849,108	2.8%	86.5%
6	$2,216,457	3.3%	61.0%	$1,709,805	2.5%	89.1%
7	$1,635,635	2.4%	63.4%	$1,095,729	1.6%	90.7%
8	$1,095,729	1.6%	65.1%	$882,015	1.3%	92.0%
9	$746,226	1.1%	66.2%	$843,347	1.3%	93.2%
10	$673,817	1.0%	67.2%	$676,035	1.0%	94.3%

Table 3-64 Top 10 units and organizations receiving synchronous condensing credits: January through September 2011 (See SOM 2010, Table 3-103)

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$54,950	7.2%	7.2%	$755,826	99.3%	99.3%
2	$54,772	7.2%	14.4%	$4,692	0.6%	100.0%
3	$51,039	6.7%	21.1%	$368	0.0%	100.0%
4	$50,856	6.7%	27.8%			
5	$46,721	6.1%	34.0%			
6	$46,106	6.1%	40.0%			
7	$44,997	5.9%	45.9%			
8	$44,031	5.8%	51.7%			
9	$43,681	5.7%	57.5%			
10	$40,101	5.3%	62.7%			

Table 3-65 Top 10 units and organizations receiving balancing generator credits: January through September 2011 (See SOM 2010, Table 3-104)

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$23,856,521	9.5%	9.5%	$61,268,139	24.3%	24.3%
2	$18,061,887	7.2%	16.6%	$37,409,463	14.9%	39.2%
3	$12,215,413	4.8%	21.5%	$25,944,152	10.3%	49.5%
4	$10,695,913	4.2%	25.7%	$23,918,514	9.5%	59.0%
5	$8,872,694	3.5%	29.3%	$22,679,037	9.0%	68.0%
6	$7,316,331	2.9%	32.2%	$12,770,557	5.1%	73.0%
7	$7,244,337	2.9%	35.0%	$12,341,886	4.9%	77.9%
8	$4,705,627	1.9%	36.9%	$7,078,417	2.8%	80.8%
9	$3,508,780	1.4%	38.3%	$6,465,058	2.6%	83.3%
10	$3,254,072	1.3%	39.6%	$5,861,871	2.3%	85.7%

Table 3-66 Top 10 units and organizations receiving lost opportunity cost credits: January through September 2011 (See SOM 2010, Table 3-105)

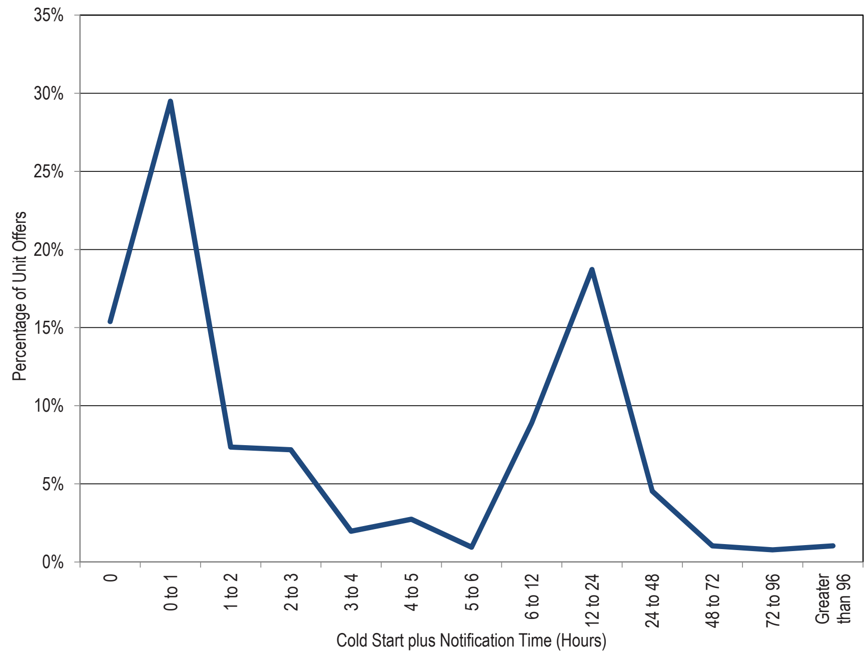
	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$6,621,926	4.2%	4.2%	$65,517,299	42.0%	42.0%
2	$6,013,853	3.9%	8.1%	$16,202,279	10.4%	52.4%
3	$5,322,286	3.4%	11.5%	$13,284,457	8.5%	61.0%
4	$5,301,680	3.4%	14.9%	$8,901,427	5.7%	66.7%
5	$4,468,104	2.9%	17.8%	$6,059,157	3.9%	70.6%
6	$4,376,201	2.8%	20.6%	$5,938,021	3.8%	74.4%
7	$4,197,395	2.7%	23.3%	$5,233,670	3.4%	77.7%
8	$3,906,302	2.5%	25.8%	$4,309,377	2.8%	80.5%
9	$3,643,638	2.3%	28.1%	$3,907,413	2.5%	83.0%
10	$2,926,531	1.9%	30.0%	$3,619,558	2.3%	85.3%

PLS (Parameter Limited Schedules) Recommendations

Startup and Notification Times

Startup and notification times are offer parameters that should, like other parameters, reflect the physical limitations of the units. There are currently no limits on startup and notification time parameters, and as a result these parameters could be used to exercise market power through economic withholding under both cost based and price based offers. This issue is currently in discussion in the PJM stakeholder process. Figure 3-12 shows the distribution of start plus notification times for the first three quarters of 2011.

Figure 3-12 Average Cold Start plus Notification Time (Hours) of PJM offers: January through September 2011 (New Figure)



Parameter Limited Schedules

Currently, parameter limited schedules are only enforced for cost-based schedules, except for emergencies, permitting the use of price-based schedule parameters as a possible method to exercise market power. (Table 3-67 is the parameter limited schedule matrix.) The parameter limited schedule should reflect the most flexible physical parameters of the unit, and there are a number of potential issues that result when a unit is not offering its most flexible parameters. For example, a unit may temporarily extend a minimum down time parameter to avoid being turned off when not economic, although there is no physical change to the unit. The result is increased operating reserve credits to the unit and operating reserve charges paid by other market participants. One way to address this issue would be a more forward looking PJM dispatch process which could better capture the operation of baseload units that were not designed to cycle daily. A unit also may offer more flexible operating parameters on a price-based schedule than on a cost-based schedule. The result can be increased operating reserve credits to the unit and charges paid by other participants when the cost-based schedule is taken in place of the price-based schedule when offer capping is implemented. One way to address this issue would be require units to include their most flexible operating parameters in their cost-based offers. These and related issues are currently being discussed in the PJM stakeholder process.

Table 3-67 PJM Unit Parameter Limited Schedule Matrix (See SOM 2010, Table 3-97)

Unit Type	Minimum Run Time (Hours)	Minimum Down Time (Hours)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio
Petroleum/Gas Steam (Pre-1985)	8 or Less	7 or Less	1 or More	7 or More	3 or More
Petroleum/Gas Steam (Post-1985)	5.5 or Less	3.5 or Less	2 or More	11 or More	2 or More
Combined-Cycle	6 or Less	4 or Less	2 or More	11 or More	1.5 or More
Sub-Critical Coal	15 or Less	9 or Less	1 or More	5 or More	2 or More
Super-Critical Coal	24 or Less	84.0	1 or More	2 or More	1.5 or More
Small Frame and Aero Combustion Turbine (0 - 29 MW)	2 or Less	2 or Less	2 or More	14 or More	1 or More
Medium Frame and Aero Combustion Turbine (30 - 125 MW)	3 or Less	2 or Less	2 or More	14 or More	1 or More
Medium-Large Frame Combustion Turbine (65 - 125 MW)	5 or Less	3 or Less	2 or More	14 or More	1 or More
Large Frame Combustion Turbine (135 - 180 MW)	5 or Less	4 or Less	2 or More	14 or More	1 or More

SECTION 4 - 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.

Highlights

- On June 1, 2011 at 0100, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. As a result, the First Energy (FE) Interface and the MICHFE Interface Pricing Point were eliminated.

- Real-time net exports decreased to -7,113.9 GWh during the first nine months of 2011 from -7,411.9 GWh during the first nine months of 2010. Day-ahead net imports were 9,066.0 GWh compared to net exports of -6,657.8 GWh during the first nine months of 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first nine months of 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period.

- The direction of power flows was not consistent with real-time energy market price differences in 56 percent of hours at the border between PJM and MISO and in 47 percent of hours at the border between PJM and NYISO during the first nine months of 2011.

- During the first nine months of 2011, net scheduled interchange was -4,176 GWh and net actual interchange was -4,524 GWh, a difference of 348 GWh or 8.3 percent, an increase from 4.8 percent during the first nine months of 2010 and 5.2 percent for the calendar year 2010. This difference is system inadvertent.

- PJM initiated 58 TLRs during the first nine months of 2011, a reduction from the 96 TLRs in the first nine months of 2010.

- The average daily volume of up-to congestion bids increased from 376 bids per day, for the period between March 1, 2009 through May 14, 2010, to 762 bids per day for the period between May 15, 2010 through September 16, 2010, to 1,987 bids per day for the period between September 17, 2010 through September 30, 2011. A significant increase in bid volume occurred following the September 17, 2010, modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids.

- Total uncollected congestion charges during the first nine months of 2011 were $11,942, compared to $2.9 million for the first nine months of 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present.

- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were $1.3 million during the first nine months of 2011, an increase from $290,515 in the first nine months of 2010.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September,* the recommendations from the 2010 State of the Market Report for PJM remain MMU recommendations.

Overview

Interchange Transaction Activity

- **American Transmission System, Inc.** (ATSI) Integration. On June 1, 2011 at 0100, First Energy's American Transmission System, Inc. Control Zone was integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduced the total number of external PJM interfaces from 21 to 20 interfaces. The integration also resulted in the elimination of the MICHFE Interface Pricing Point, reducing the total number of interface pricing points from 17 to 16.[1]

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first nine months of 2011, PJM was a net importer of energy

1 The tables and figures within this section continue to show that the FE Interace and the MICHFE Interface Pricing Points existed in June 2011, to account for the single hour in June where FE was still an external interface.

in the Real-Time Energy Market in January, and a net exporter of energy in the remaining months. During the first nine months of 2010, PJM was a net exporter of energy in the Real-Time Energy Market in all months. In the Real-Time Energy Market, monthly net interchange averaged -790.4 GWh compared to -823.5 GWh for the first nine months of 2010.[2] Gross monthly import volumes averaged 3,479.5 GWh compared to 3,475.1 GWh for the first nine months of 2010 while gross monthly exports averaged 4,269.9 GWh compared to 4,298.6 GWh for the first nine months of 2010.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first nine months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market from January through June, and a net exporter of energy in the remaining months. During the first nine months of 2010, PJM was a net importer of energy in the Day-Ahead Energy Market only in August and a net exporter of energy in the remaining months. In the Day-Ahead Energy Market, monthly net interchange averaged 1,007.4 GWh compared to -739.7 GWh for the first nine months of 2010. Gross monthly import volumes averaged 10,561.2 GWh compared to 7,075.1 GWh for the first nine months of 2010 while gross monthly exports averaged 9,553.8 GWh compared to 7,814.8 GWh for the first nine months of 2010.

  The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first nine months of 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. For the first six months of 2011, the overall net PJM imports would have been net exports but for the net up-to congestion transaction imports. Figure 4-2 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 1,462 bids per day, with an average cleared volume of 501,662 MWh per day, during the first nine months of 2011, compared to an average of 423 bids per day, with an average cleared volume of 297,071 MWh per day, during the first nine months of 2010.

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** During the first nine months of 2011, gross imports in the Day-Ahead Energy Market were 307 percent of gross imports in the Real-Time Energy Market (204 percent for the first nine months of 2010). During the first nine months of 2011, gross exports in the Day-Ahead Energy Market were 224 percent of gross exports in the Real-Time Energy Market (182 percent for the first nine months of 2010). During the first nine months of 2011, net interchange was 9,066.0 GWh in the Day-Ahead Energy Market and -7,113.9 GWh in the Real-Time Energy Market compared to -6,657.8 GWh in the Day-Ahead Energy Market and -7,411.9 GWh in the Real-Time Energy Market for the first nine months of 2010.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, during the first nine months of 2011, there were net exports at 14 of PJM's 21 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 71 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 23 percent, PJM/MidAmerican Energy Company (MEC) with 20 percent, PJM/Cinergy Corporation (CIN) with 14 percent and PJM/Neptune (NEPT) with 14 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 41 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interfaces had net imports, with two importing interfaces accounting for 78 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 60 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 18 percent.[3]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, during the first nine months of 2011, there were net exports at 15 of PJM's 21 interfaces. The top three net exporting interfaces accounted for 58 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 23 percent, PJM/Neptune (NEPT) with 19 percent and PJM/Linden (LIND) with 16 percent. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND) together represented 27 percent of the total net PJM exports in the Day-Ahead Energy Market. Six PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 95 percent of the total net imports: PJM/OVEC with 39 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 31 percent and PJM/Michigan Electric Coordinated System (MECS) with 25 percent.

2 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

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

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent Transmission System Operator, Inc. (MISO) Interface Prices.** During the first nine months of 2011, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. During the first nine months of 2011, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $34.36 while the MISO LMP at the border was $35.71, a difference of $1.35. While the average hourly LMP difference at the PJM/MISO border was only $1.35, the average of the absolute values of the hourly differences was $12.54. The average hourly flow during the first nine months of 2011 was -1,628 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 44 percent of hours during the first nine months of 2011. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $16.39. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $9.73. During the first nine months of 2011, 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 $15.49. 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 $23.68. 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 $23.47. 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 $8.02.

- **PJM and New York ISO Interface Prices.** During the first nine months of 2011, 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. During the first nine months of 2011, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. During the first nine months of 2011, the PJM average hourly LMP at the PJM/NYISO border was $46.75 while the NYISO LMP at the border was $45.03, a difference of $1.72. While the average hourly LMP difference at the PJM/NYISO border was only $1.72, the average of the absolute value of the hourly difference was $15.19. The average hourly flow during the first nine months of 2011 was -630 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 53 percent of the hours during the first nine months of 2011. During the first nine months of 2011, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $13.68. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $16.68. During the first nine months of 2011, 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 $11.84. 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 $32.14. 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 $32.08. 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 $13.82.

- **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). The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. During the first nine months of 2011, the average difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. During the first nine months of 2011, the PJM average hourly LMP at the Neptune Interface was $51.63 while the NYISO LMP at the Neptune Bus was $58.59, a difference of $6.96. While the average hourly LMP difference at the PJM/Neptune border was $6.96, the average of the absolute value of the hourly difference was $22.37. The average hourly flow during the first nine months of 2011 was -484

MW. (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 percent of the hours during the first nine months of 2011. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average pirce difference was $22.15. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $21.75.

- **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 and NYISO. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provided that power flows would only be from PJM to New York. On March 31, 2011, PJM, on behalf of Linden VFT, LLC, submitted a revision to Schedule 16 of the PJM Open Access Transmission Tariff which requested the addition of Schedule 16-A to the Tariff to provide the terms and conditions for transmission service on the Linden VFT Facility for imports into PJM.[4] On June 1, 2011, the Tariff revision became effective, allowing for the bidirectional flow across the Linden VFT facility. During the first nine months of 2011, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. During the first nine months of 2011, the PJM average hourly LMP at the Linden Interface was $51.13 while the NYISO LMP at the Linden Bus was $52.93, a difference of $1.80. While the average hourly LMP difference at the PJM/Linden border was $1.80, the average of the absolute value of the hourly difference was $18.71. The average hourly flow during the first nine months of 2011 was -146 MW. (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 62 percent of the hours during the first nine months of 2011. Following June 1, 2011, when bidirectional flows were permitted across the Linden VFT Facility, a total of 560 hours, out of the 2,927 hours in June, were imports into PJM. Of those 560 hours, 335 hours were economic (i.e. the NYISO/PJM Interface price was lower than the PJM/NYISO Interface price). When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM (335 hours), the average price difference was $32.65. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when power flows were from NYISO to PJM (225 hours), the average price difference was $28.42.

4 See Docket No. ER11-3250-000 (March 31, 2011).

- **Hudson DC Line.** The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection will be a submarine AC cable system. While the Hudson DC line is 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 current in-service date for this line is January 31, 2012.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[5] On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It also 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 does not include provisions for market based congestion management or other market to market activity, and, in 2008, at the request of PJM, PJM and NYISO began discussion of a market based congestion management protocol, which continued during the first nine months of 2011.

- **PJM and MISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during the first nine months of 2011. 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.

5 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) (Accessed November 10, 2011) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (2,285 KB).

- **PJM, MISO and TVA Joint Reliability Coordination Agreement.**[6] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of MISO and PJM and the service territory of TVA. The agreement continued to be in effect during the first nine months of 2011.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[7] 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. The agreement remained in effect during the first nine months of 2011. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP).

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[8] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC SERC Reliability Corporation (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

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.** During the first nine months of 2011, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[9] This protocol allows Con Edison to elect up to the flow specified in each of two contracts through the PJM Day-Ahead Energy Market. A 600 MW contract is for firm service and a 400 MW contract has a priority higher than non-firm service, but lower 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.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the 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 defined as the difference between actual and scheduled power flows at one or more specific interfaces.

  Loop flow 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. 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 pricing with physical flows and their impacts on the transmission system. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

  During the first nine months of 2011, net scheduled interchange was -4,176 GWh and net actual interchange was -4,524 GWh, a difference of 348 GWh or 8.3 percent, an increase from 4.8 percent during the first nine months of 2010 and 5.2 percent for the calendar year 2010. This difference is system inadvertent.

  Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

  A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and non market areas. A complete analysis of loop flow would improve the overall transparency of

6 See "Congestion Management Process (CMP) Master" (May 1, 2008) (November 10, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).
7 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) (Accessed November 10, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (642 KB).
8 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed November 10, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).
9 See 111 FERC ¶ 61,228 (2005).

electicity transactions. To adequately investigate the causes of loop flows, complete data are required. The MMU has previously requested access to the data necessary to complete this analysis.[10] On April 21, 2011, FERC issued a Notice of Proposed Rulemaking addressing the issues associated with access to loop flow data by the Commission staff and market monitors.[11] On June 27, 2011, the North American market monitors provided comments to the Notice of Proposed Rulemaking, supporting the consideration to making the complete electronic tagging data used to schedule the transmission of electric power in wholesale markets available to entities involved in market monitoring functions.[12]

- **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As it had in 2010, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-12,779 GWh during the first nine months of 2011 and -15,106 GWh for the calendar year 2010). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (3,030 GWh during the first nine months of 2011 and 4,015 GWh for the calendar year 2010). The net difference between scheduled flows and actual flows at the PJM/MECS Interface was exports while the net difference at the PJM/TVA Interface was imports.

- **Loop Flows at PJM's Southern Interfaces.** The difference between scheduled and actual power flows at PJM's southern interfaces was significant during the first nine months of 2011. PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) are in the west. The largest differences in the west were at the TVA Interface. The net scheduled power flow at the TVA Interface was 731 GWh and the actual flow was 3,761 GWh, a difference of 3,030 GWh. PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK are in the east. The largest differences in the east were at the CPLE Interface. The net scheduled power flow at the CPLE Interface was 18 GWh and the actual flow was 6,134 GWh, a difference of 6,116 GWh.

- **PJM Transmission Loading Relief Procedures (TLRs).** During the first nine months of 2011, PJM issued 58 TLRs of level 3a or higher. Of the 58 TLRs issued, 33 events were TLR level 3a, and the remaining 25 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. The fact that PJM issued only 58 TLRs during the first nine months of 2011, compared to 96 during the first nine months of 2010, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM's operating rules allow PJM to reconfigure the transmission system prior to reaching system operating limits that would require the need for higher level TLRs.

- **Marginal Loss Surplus Allocation.** On May 15, 2010, in an order on complaint, the Commission required PJM to correct an inconsistency in the tariff language defining the method for allocating the marginal loss surplus based on contributions to the fixed costs of the transmission system.[13] PJM's tariff modification resulted in an allocation of the marginal loss surplus based on usage of the system rather than based on the dollar contribution to the fixed costs of the transmission system. The inconsistency between the allocation principle defined by FERC and the actual allocation created an incentive for market participants to enter noneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus.

  As a result, on September 17, 2010, the marginal loss surplus allocation methodology was modified to mitigate the incentive to submit noneconomic transactions solely to receive a loss surplus allocation.

- **Up-To Congestion.** The May 15, 2010, modification to the marginal loss surplus allocation provided an allocation to up-to congestion transactions. In June and July of 2010, there was a significant increase in the total up-to congestion bids. This increase in activity was the result of the changes to the allocation methodology that provided an inappropriate incentive to submit noneconomic up-to congestion transactions solely to obtain a portion of the loss surplus.

  As part of the September 17, 2010 marginal loss surplus allocation modification, the up-to congestion product was modified to eliminate the requirement for up-to congestion transactions to obtain transmission service. In order to minimize the effects of eliminating the transmission requirement for up-to congestion transactions, PJM created a new product on the OASIS, called Up-to Congestion. Market participants are still required to access the PJM OASIS and obtain an up-to congestion

10 See the *2010 State of the Market Report for PJM*, Volume II, "Section 4, Interchange Transactions" at "Data Required for Full Loop Flow Analysis."
11 See 135 FERC ¶ 61,052 (April 21, 2011).
12 See "Joint Comments of the North American Market Monitors." Docket No. RM11-12-000 (June 27, 2011)
13 See 131 FERC ¶ 61,024 (2010) (order denying rehearing and accepting compliance filing); 126 FERC ¶ 61,164 (2009) (Order on request for clarification).

reservation. However, the product is not limited by ATC, nor is there a charge associated with the product. The sole purpose of this product is to allow market participants to specify specific sources and sinks for which up-to congestion transactions will be evaluated in the Day-Ahead Market.

Prior to the May 15, 2010, modification to the marginal loss surplus allocation, the average daily volume of up-to congestion was 376 bids per day (March 1, 2009 through May 14, 2010). The average daily volume of up-to congestion transactions increased to 762 bids per day for the period between the initial May 15, 2010, modification and the additional modification to the marginal loss surplus allocation methodology made on September 17, 2010. The average daily volume of up-to congestion bids further increased to 1,987 bids per day following the additional modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids, which was implemented as part of the September 17, 2010 marginal loss surplus allocation methodology changes (September 17, 2010, through September 30, 2011). (See Table 4-13.)

Effective May 16, 2011, for the May 17, 2011, Day-Ahead Market, PJM modified the available locations for up-to congestion transactions to eliminate the ability to submit up-to congestion bids at the CPLEIMP, CPLEEXP, DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP Interface pricing points. These interface pricing points were eliminated to avoid wheeling up-to congestion transactions from being submitted at the same interface to arbitrage price differentials between the Day-Ahead and Real-Time Energy Markets created by existing JOA's (for example, using an import pricing point of CPLEIMP and an export pricing point of CPLEEXP or SOUTHEXP). The MMU agrees with the elimination of these interfaces for up-to congestion transactions, as wheeling transactions at the same interface are not permitted in the Real-Time Energy Market.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** When reserving non-firm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

  Total uncollected congestion charges during the first nine months of 2011 were $11,942, compared to $2.9 million for the first nine months of 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present.

  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. PJM stakeholders approved the changes recommended by the MMU. These modifications are currently being evaluated by PJM to determine if tariff or operating agreement changes are necessary prior to implementation.

- **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.[14] These modifications are currently being evaluated by PJM to develop an implementation plan.

- **Spot Import.** In 2009, the MMU and PJM jointly addressed a concern regarding the underutilization of spot import service. Because spot import service is available at no cost, and is limited by available transfer capabilities (ATC), market participants were able to reserve all of the available service with no economic risk. The market participants could

14 See "Meeting Minutes" Minutes from PJM's MIC meeting (May 16, 2011) (Accessed on November 10, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> 121 KB).

then choose not to submit a transaction utilizing the service if they did not believe the transaction would be economic. By reserving the spot import service and not scheduling against it, they effectively withheld the service from other market participants who wished to utilize it.

To address the issue, PJM implemented new timing requirements that retracted spot import reservations if they were associated with a NERC Tag within 30 minutes of making the reservation. Although this resulted in an increase in scheduling, some participants were still able to schedule but not use spot import service to flow energy. As a result, the MMU and PJM recommended that PJM revert to unlimited ATC for non-firm willing to pay congestion service. The PJM Stakeholders agreed with the recommendation, and requested that PJM determine what would be needed to implement the change.

PJM reported that further modifications to the various JOAs would be required to revert to unlimited ATC for non-firm willing to pay congestion service. To modify the JOA, both parties must be in agreement with any proposed changes. PJM reported that MISO and Progress Energy Carolinas, Inc., counterparties to two JOAs, expressed concerns about allowing for unlimited ATC, citing potential reliability concerns, and were unwilling to make the modifications.

As an alternative to creating an unlimited amount of ATC, PJM suggested including a utilization factor in the ATC calculation for non-firm service. This utilization factor is the ratio of utilized transmission on a particular path to the amount of that transmission reserved when determining how much transmission should be granted. For example, if a path has 1,000 MW of ATC available, and the utilization factor is sixty percent, rather than reducing the ATC to zero when a 1,000 MW reservation is made, there would still be 400 MW of ATC available to be requested. Including the utilization factor will allow PJM to adjust the amount of ATC available to permit a more efficient use of the transmission system. This proposed methodology was approved by PJM stakeholders during the third quarter of 2011, with a targeted implementation date in the fourth quarter of 2011.

- **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 initially a valuable tool for market participants. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants. The value that dispatchable transactions once provided market participants no longer exist, but the risk to other market participants is substantial, as they are subject to providing the operating reserve credits. Dispatchable transactions now only serve as a potential mechanism for receiving those operating reserve credits. During the first nine months of 2011, $1.3 million in balancing operating reserve credits were paid due to the uneconomic loading of dispatchable transactions compared to $290,515 during first nine months of 2010.

  The MMU recommended that dispatchable transactions either be eliminated as a product in the PJM Real-Time Energy Market, or to keep the product, eliminate the operating reserve credits allocated to importing dispatchable transactions and to incorporate the product into the Intermediate Term Security Constrained Economic Dispatch (ITSCED) tool. On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into the ITSCED application.[15] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011.

- **Internal Bilateral Transactions.** In the third quarter of 2011, it was discovered that a number of companies had been utilizing internal bilateral transactions to inappropriately reduce, or eliminate, their exposure to balancing operating reserve (BOR) charges associated with their PJM Day-Ahead Market positions.

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 hedging tools (FTRs and Auction

15 See “Meeting Minutes“ Minutes from PJM’s MIC meeting (July 13, 2011) (Accessed on November 10, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx> (121 KB).

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.

On June 1, 2011, at 0100, the American Transmission System, Inc. Control Zone was integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduced the total number of external PJM interfaces from 21 to 20 interfaces. Additionally, following the ATSI integration, the MICHFE Interface Pricing Point was eliminated, reducing the total number of interface pricing points from 17 to 16.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first nine months of 2011, including evolving transaction patterns, economics and issues. During the first nine months of 2011, PJM was a net exporter of energy in the Real-Time Market and a net importer of energy in the Day-Ahead Market. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first nine months of 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. A large share of both import and export activity occurred at a small number of interfaces. Four interfaces accounted for 71 percent of the total real-time net exports and two interfaces accounted for 78 percent of the real-time net import volume. Three interfaces accounted for 58 percent of the total day-ahead net exports and three interfaces accounted for 95 percent of the day-ahead net import volume.

During the first nine months of 2011, 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 many hours, 56 percent between PJM and MISO and 47 percent between PJM and NYISO. The MMU recommends that PJM 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 reliance 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.

Interactions between PJM and other balancing authorities should be governed by the same market principles that govern transactions within PJM. That is not yet the case. The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through September 2011 (See 2010 SOM, Figure 4-1)

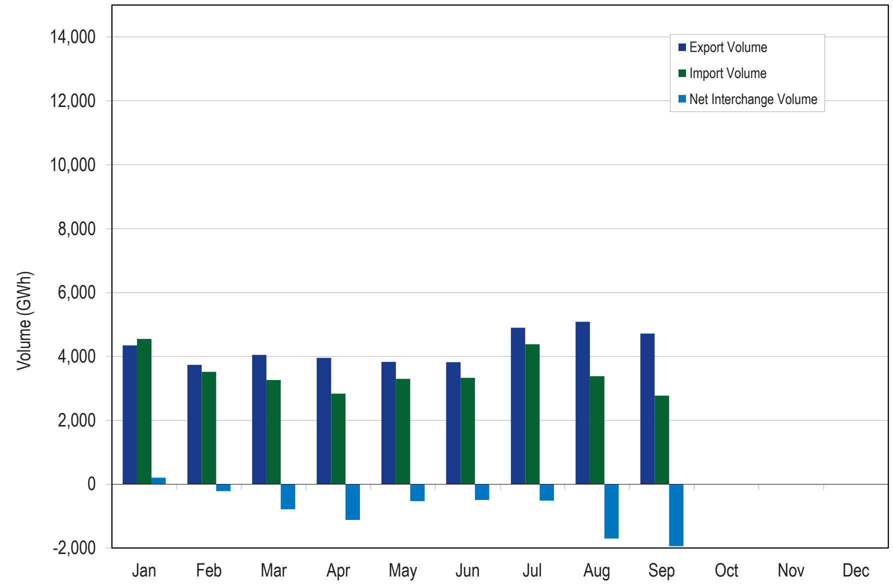


Figure 4-2 PJM day-ahead scheduled imports and exports: January through September 2011 (See 2010 SOM, Figure 4-2)

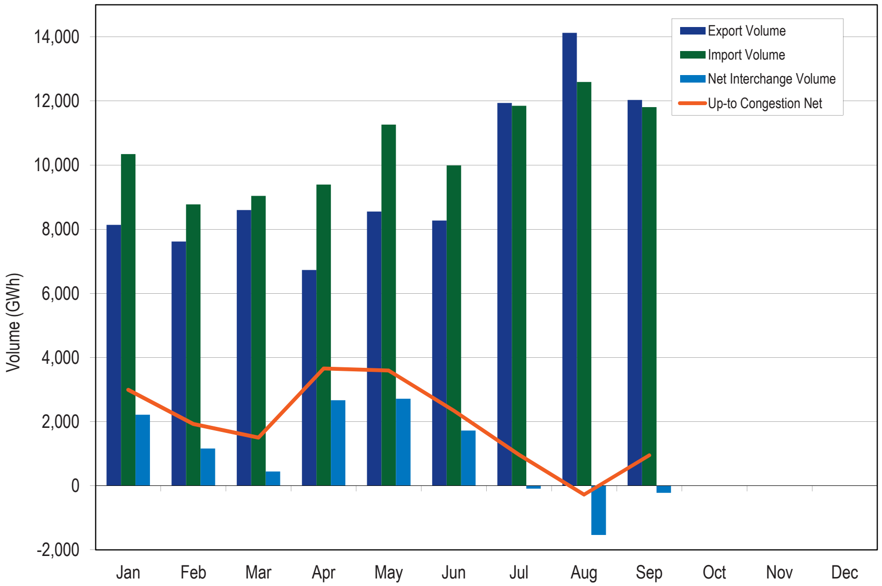


Figure 4-3 PJM real-time scheduled import and export transaction monthly volume history: 1999 through September 2011 (See 2010 SOM, Figure 4-3)

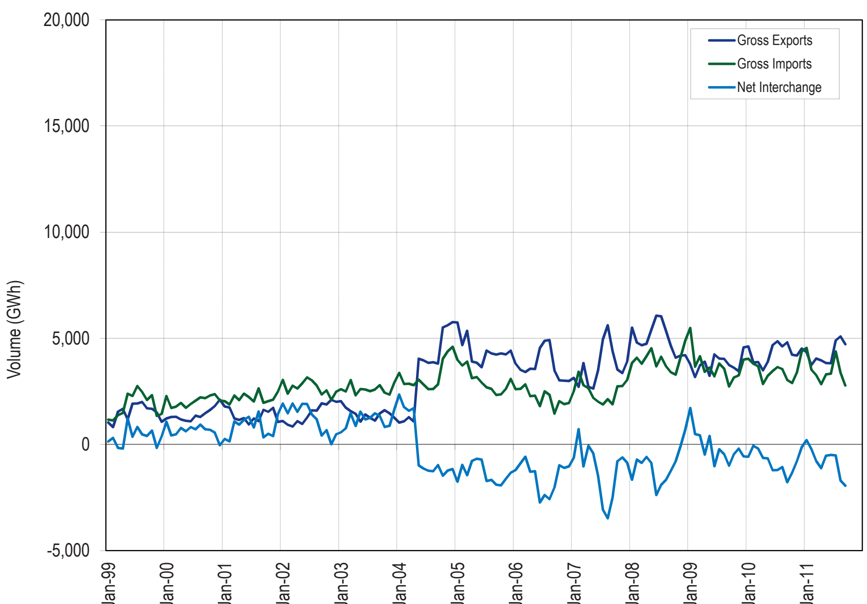
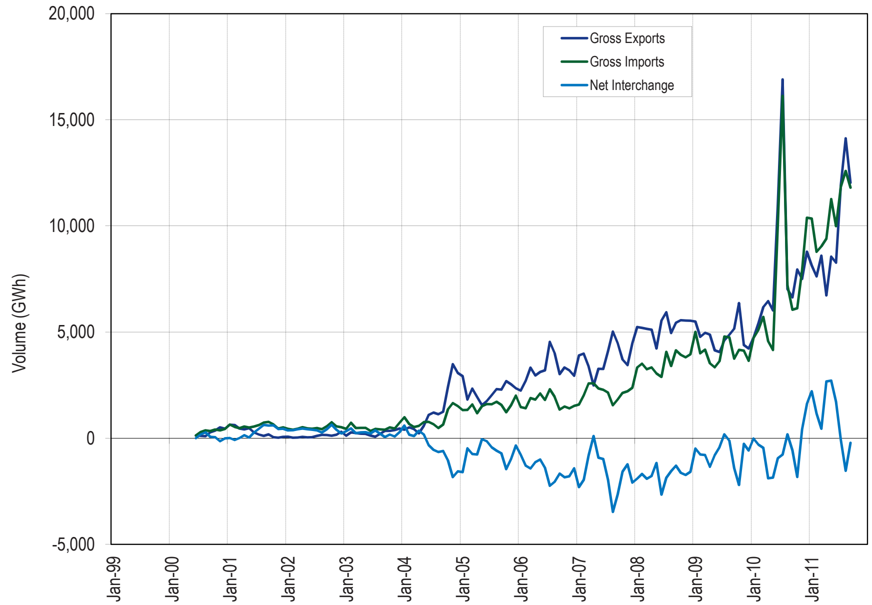


Figure 4-4 PJM day-ahead scheduled import and export transaction monthly volume history: June 2000 through September 2011 (New Figure)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through September 2011 (See 2010 SOM, Table 4-1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(162.6)	(76.3)	(85.5)	(48.3)	(77.6)	(59.1)	(75.1)	(150.1)	(129.5)	(864.1)
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	2.4
DUK	(25.6)	218.7	(17.1)	12.7	34.7	(36.8)	33.9	(289.3)	(132.2)	(201.0)
EKPC	(61.4)	(10.1)	5.6	135.0	41.4	106.4	107.1	100.7	80.4	505.1
LGEE	392.9	385.9	314.6	200.0	241.7	321.8	303.1	246.6	327.6	2,734.2
MEC	(426.0)	(403.3)	(462.2)	(463.2)	(478.5)	(456.3)	(675.5)	(565.8)	(616.7)	(4,547.5)
MISO	(77.3)	(389.0)	(744.4)	(1,131.2)	(495.8)	(675.9)	(576.0)	(752.7)	(1,187.4)	(6,029.7)
ALTE	(116.1)	(128.3)	(76.0)	(4.5)	(7.6)	(105.7)	(210.6)	(193.5)	(378.8)	(1,221.1)
ALTW	(30.9)	(14.5)	(28.6)	(49.9)	(68.8)	(83.2)	(119.3)	(83.2)	(249.3)	(727.7)
AMIL	(2.9)	45.5	14.3	8.6	37.9	(17.6)	(34.8)	(101.8)	(120.2)	(171.0)
CIN	(85.5)	(314.7)	(454.6)	(713.9)	(242.7)	(423.9)	(338.1)	(113.3)	(376.2)	(3,062.9)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	149.9	(43.9)	(159.1)	(250.2)	(251.0)	0.2	0.0	0.0	0.0	(554.1)
IPL	21.8	3.5	8.8	(3.3)	11.0	(12.8)	(60.6)	(111.3)	(30.9)	(173.8)
MECS	193.0	190.8	112.6	33.2	160.1	128.9	413.3	218.7	223.3	1,673.9
NIPS	(114.3)	(51.0)	(69.7)	(72.6)	(53.7)	(71.9)	(80.0)	(62.6)	(42.8)	(618.6)
WEC	(92.3)	(76.4)	(92.1)	(78.6)	(81.0)	(89.9)	(145.9)	(305.7)	(212.5)	(1,174.4)
NYISO	(1,361.0)	(1,279.3)	(1,032.0)	(864.2)	(731.7)	(673.6)	(939.5)	(1,348.3)	(1,150.1)	(9,379.7)
LIND	(159.1)	(148.1)	(117.7)	(131.7)	(93.0)	(80.4)	(27.6)	(93.4)	(124.6)	(975.6)
NEPT	(412.9)	(378.8)	(383.7)	(290.8)	(387.5)	(241.0)	(372.8)	(460.1)	(313.2)	(3,240.8)
NYIS	(789.0)	(752.4)	(530.6)	(441.7)	(251.2)	(352.2)	(539.1)	(794.8)	(712.3)	(5,163.3)
OVEC	1,242.2	1,110.7	1,065.8	1,019.0	1,030.7	1,014.6	1,040.8	1,011.9	828.9	9,364.6
TVA	681.6	222.8	170.3	19.9	(98.5)	(36.7)	264.3	41.8	36.3	1,301.8
Total	202.8	(219.9)	(784.9)	(1,120.3)	(533.6)	(493.2)	(516.9)	(1,705.2)	(1,942.7)	(7,113.9)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through September 2011 (See 2010 SOM, Table 4-2)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	6.4	7.4	4.6	6.6	23.4	67.7	74.7	37.6	13.0	241.4
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	2.4
DUK	271.7	309.8	186.2	208.2	197.7	184.4	299.8	121.8	103.3	1,882.9
EKPC	31.7	46.5	41.0	143.3	85.5	112.3	116.7	110.3	85.9	773.2
LGEE	393.0	386.3	324.1	233.6	250.3	334.6	322.7	268.5	328.2	2,841.3
MEC	53.2	30.8	19.1	0.0	0.0	0.0	0.0	0.0	6.0	109.1
MISO	1,141.5	833.9	736.6	409.5	718.2	542.8	998.2	714.4	599.0	6,694.1
ALTE	0.0	0.0	0.0	0.0	0.0	0.2	1.6	0.0	0.0	1.8
ALTW	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.6	0.0	1.5
AMIL	23.9	68.0	42.2	26.0	55.4	37.8	85.2	75.0	7.3	420.8
CIN	400.0	270.3	315.2	180.8	348.0	260.0	359.4	344.9	261.8	2,740.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	436.8	220.5	122.3	55.5	71.2	0.3	0.0	0.0	0.0	906.6
IPL	25.4	4.8	15.3	5.6	19.3	66.9	89.3	37.1	39.6	303.3
MECS	250.9	270.3	241.4	141.4	224.3	176.7	460.7	256.8	289.3	2,311.8
NIPS	0.0	0.0	0.2	0.2	0.0	0.0	2.0	0.0	0.0	2.4
WEC	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	5.5
NYISO	681.0	534.7	646.6	686.3	911.4	976.1	1,144.6	961.5	731.5	7,273.7
LIND	0.0	0.0	0.0	0.0	0.1	14.5	52.0	28.2	10.8	105.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	681.0	534.7	646.6	686.3	911.3	961.6	1,092.6	933.3	720.7	7,168.1
OVEC	1,242.2	1,110.7	1,091.3	1,019.0	1,030.7	1,014.6	1,063.6	1,013.7	834.7	9,420.5
TVA	725.7	255.5	212.0	128.8	79.7	92.0	360.3	152.7	69.8	2,076.5
Total	4,546.4	3,515.6	3,261.5	2,835.3	3,296.9	3,326.9	4,380.6	3,380.5	2,771.4	31,315.1

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through September 2011 (See 2010 SOM, Table 4-3)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	169.0	83.7	90.1	54.9	101.0	126.8	149.8	187.7	142.5	1,105.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	297.3	91.1	203.3	195.5	163.0	221.2	265.9	411.1	235.5	2,083.9
EKPC	93.1	56.6	35.4	8.3	44.1	5.9	9.6	9.6	5.5	268.1
LGEE	0.1	0.4	9.5	33.6	8.6	12.8	19.6	21.9	0.6	107.1
MEC	479.2	434.1	481.3	463.2	478.5	456.3	675.5	565.8	622.7	4,656.6
MISO	1,218.8	1,222.9	1,481.0	1,540.7	1,214.0	1,218.7	1,574.2	1,467.1	1,786.4	12,723.8
ALTE	116.1	128.3	76.0	4.5	7.6	105.9	212.2	193.5	378.8	1,222.9
ALTW	30.9	14.5	28.6	49.9	68.8	84.1	119.3	83.8	249.3	729.2
AMIL	26.8	22.5	27.9	17.4	17.5	55.4	120.0	176.8	127.5	591.8
CIN	485.5	585.0	769.8	894.7	590.7	683.9	697.5	458.2	638.0	5,803.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	286.9	264.4	281.4	305.7	322.2	0.1	0.0	0.0	0.0	1,460.7
IPL	3.6	1.3	6.5	8.9	8.3	79.7	149.9	148.4	70.5	477.1
MECS	57.9	79.5	128.8	108.2	64.2	47.8	47.4	38.1	66.0	637.9
NIPS	114.3	51.0	69.9	72.8	53.7	71.9	82.0	62.6	42.8	621.0
WEC	96.8	76.4	92.1	78.6	81.0	89.9	145.9	305.7	213.5	1,179.9
NYISO	2,042.0	1,814.0	1,678.6	1,550.5	1,643.1	1,649.7	2,084.1	2,309.8	1,881.6	16,653.4
LIND	159.1	148.1	117.7	131.7	93.1	94.9	79.6	121.6	135.4	1,081.2
NEPT	412.9	378.8	383.7	290.8	387.5	241.0	372.8	460.1	313.2	3,240.8
NYIS	1,470.0	1,287.1	1,177.2	1,128.0	1,162.5	1,313.8	1,631.7	1,728.1	1,433.0	12,331.4
OVEC	0.0	0.0	25.5	0.0	0.0	0.0	22.8	1.8	5.8	55.9
TVA	44.1	32.7	41.7	108.9	178.2	128.7	96.0	110.9	33.5	774.7
Total	4,343.6	3,735.5	4,046.4	3,955.6	3,830.5	3,820.1	4,897.5	5,085.7	4,714.1	38,429.0

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through September 2011 (See 2010 SOM, Table 4-4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(11.3)	89.8	126.7	234.5	159.9	(83.0)	(322.5)	(673.9)	(617.9)	(1,097.7)
CPLW	17.1	6.4	1.9	11.0	6.0	15.4	45.7	42.1	18.3	163.9
DUK	91.7	115.8	41.0	789.1	234.0	(240.7)	(617.8)	(495.5)	39.1	(43.3)
EKPC	(27.5)	(18.4)	27.8	6.8	(5.3)	0.9	(9.7)	(2.9)	(0.3)	(28.6)
LGEE	19.0	1.8	2.0	16.6	35.6	1.8	22.5	19.7	(2.1)	116.9
MEC	(458.7)	(421.4)	(463.2)	(455.2)	(472.2)	(437.3)	(542.0)	(493.2)	(512.4)	(4,255.6)
MISO	2,144.3	904.6	(182.2)	697.2	452.4	1,481.0	1,717.5	1,084.0	709.7	9,008.5
ALTE	1,996.5	908.2	99.1	833.9	1,037.3	1,333.0	911.8	730.0	583.1	8,432.9
ALTW	164.8	(49.7)	(48.1)	(40.1)	(7.3)	139.3	(0.4)	(42.6)	(205.5)	(89.6)
AMIL	34.6	70.2	67.5	31.0	33.6	(4.6)	74.1	(129.5)	(687.4)	(510.5)
CIN	(125.8)	(90.5)	(175.1)	(94.3)	(18.1)	(131.4)	(0.3)	100.0	178.4	(357.1)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.7)	0.0	(1.7)
FE	(189.4)	(339.7)	(317.2)	(479.3)	(1,299.6)	(1.5)	0.0	0.0	0.0	(2,626.7)
IPL	(175.6)	(162.6)	(163.9)	(75.1)	(123.5)	(97.9)	(152.7)	(105.9)	(125.4)	(1,182.6)
MECS	742.4	580.2	567.2	591.2	992.5	336.2	932.0	816.5	1,150.4	6,708.6
NIPS	(280.6)	(111.0)	(130.3)	(65.9)	(108.8)	(90.8)	(50.9)	(1.7)	(6.8)	(846.8)
WEC	(22.6)	99.5	(81.4)	(4.2)	(53.7)	(1.3)	3.9	(281.1)	(177.1)	(518.0)
NYISO	(892.0)	(681.9)	(496.7)	(220.9)	611.3	(242.7)	(987.4)	(1,169.3)	(902.6)	(4,982.2)
LIND	(105.0)	(104.7)	(77.9)	(110.8)	(75.0)	(171.2)	(659.8)	(740.5)	(822.6)	(2,867.5)
NEPT	(427.9)	(379.7)	(385.0)	(298.1)	(405.2)	(250.0)	(396.6)	(508.6)	(339.6)	(3,390.7)
NYIS	(359.1)	(197.5)	(33.8)	188.0	1,091.5	178.5	69.0	79.8	259.6	1,276.0
OVEC	1,046.0	1,051.1	1,279.5	1,502.7	1,636.3	1,167.6	1,025.6	643.8	1,163.3	10,515.9
TVA	282.8	111.2	106.7	85.9	56.5	55.6	(422.1)	(489.8)	(118.6)	(331.8)
Total	2,211.4	1,159.0	443.5	2,667.7	2,714.5	1,718.6	(90.2)	(1,535.0)	(223.5)	9,066.0

Table 4-5 Day-ahead gross import volume by interface (GWh): January through September 2011 (See 2010 SOM, Figure 4-5)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	137.6	146.3	197.4	305.0	242.6	29.5	40.6	45.3	48.2	1,192.5
CPLW	19.5	6.5	8.1	13.9	24.6	27.2	64.9	69.3	47.9	281.9
DUK	150.8	155.5	88.5	935.0	269.0	50.9	99.2	50.2	55.3	1,854.4
EKPC	5.4	0.0	28.3	6.8	6.3	2.8	0.2	0.3	0.3	50.4
LGEE	21.6	2.1	13.5	17.1	40.8	41.6	71.0	21.6	14.1	243.4
MEC	21.7	19.8	20.1	8.2	15.9	67.5	102.8	107.1	106.2	469.3
MISO	7,393.7	5,782.6	5,316.8	4,391.0	5,686.9	5,791.8	7,048.6	7,143.8	6,968.3	55,523.5
ALTE	4,872.3	3,576.6	3,109.0	2,156.0	2,959.3	3,808.9	3,588.3	3,520.1	3,761.2	31,351.7
ALTW	375.6	52.1	29.0	19.3	74.1	284.8	183.7	129.2	51.9	1,199.7
AMIL	44.8	71.1	70.7	34.2	35.8	45.2	77.2	34.2	50.9	464.1
CIN	266.2	440.5	360.6	511.2	263.4	728.0	760.3	692.0	662.2	4,684.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	232.7	140.5	141.0	55.5	17.0	0.0	0.0	0.0	0.0	586.7
IPL	17.0	2.9	0.0	6.5	2.8	1.7	0.8	1.0	4.8	37.5
MECS	1,409.4	1,207.9	1,438.1	1,402.0	2,167.9	772.1	2,254.1	2,644.6	2,260.5	15,556.6
NIPS	32.0	48.2	27.0	33.9	11.6	29.2	33.2	35.2	26.0	276.3
WEC	143.7	242.8	141.4	172.4	155.0	121.9	151.0	87.5	150.8	1,366.5
NYISO	910.1	988.6	1,149.1	1,399.2	2,467.1	1,560.2	1,666.6	1,763.1	1,997.8	13,901.8
LIND	0.0	0.0	0.0	0.0	0.0	8.7	29.1	22.2	0.8	60.8
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	910.1	988.6	1,149.1	1,399.2	2,467.1	1,551.5	1,637.5	1,740.9	1,997.0	13,841.0
OVEC	1,272.8	1,355.2	1,898.8	1,976.7	2,223.0	1,886.6	2,006.4	2,750.1	2,146.5	17,516.1
TVA	412.1	318.7	318.9	341.8	286.8	529.3	748.6	639.7	421.3	4,017.2
Total	10,345.3	8,775.3	9,039.5	9,394.7	11,263.0	9,987.4	11,848.9	12,590.5	11,805.9	95,050.5

Table 4-6 Day-ahead gross export volume by interface (GWh): January through September 2011 (See 2010 SOM, Figure 4-6)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	148.9	56.5	70.7	70.5	82.7	112.5	363.1	719.2	666.1	2,290.2
CPLW	2.4	0.1	6.2	2.9	18.6	11.8	19.2	27.2	29.6	118.0
DUK	59.1	39.7	47.5	145.9	35.0	291.6	717.0	545.7	16.2	1,897.7
EKPC	32.9	18.4	0.5	0.0	11.6	1.9	9.9	3.2	0.6	79.0
LGEE	2.6	0.3	11.5	0.5	5.2	39.8	48.5	1.9	16.2	126.5
MEC	480.4	441.2	483.3	463.4	488.1	504.8	644.8	600.3	618.6	4,724.9
MISO	5,249.4	4,878.0	5,499.0	3,693.8	5,234.5	4,310.8	5,331.1	6,059.8	6,258.6	46,515.0
ALTE	2,875.8	2,668.4	3,009.9	1,322.1	1,922.0	2,475.9	2,676.5	2,790.1	3,178.1	22,918.8
ALTW	210.8	101.8	77.1	59.4	81.4	145.5	184.1	171.8	257.4	1,289.3
AMIL	10.2	0.9	3.2	3.2	2.2	49.8	3.1	163.7	738.3	974.6
CIN	392.0	531.0	535.7	605.5	281.5	859.4	760.6	592.0	483.8	5,041.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	1.7
FE	422.1	480.2	458.2	534.8	1,316.6	1.5	0.0	0.0	0.0	3,213.4
IPL	192.6	165.5	163.9	81.6	126.3	99.6	153.5	106.9	130.2	1,220.1
MECS	667.0	627.7	870.9	810.8	1,175.4	435.9	1,322.1	1,828.1	1,110.1	8,848.0
NIPS	312.6	159.2	157.3	99.8	120.4	120.0	84.1	36.9	32.8	1,123.1
WEC	166.3	143.3	222.8	176.6	208.7	123.2	147.1	368.6	327.9	1,884.5
NYISO	1,802.1	1,670.5	1,645.8	1,620.1	1,855.8	1,802.9	2,654.0	2,932.4	2,900.4	18,884.0
LIND	105.0	104.7	77.9	110.8	75.0	179.9	688.9	762.7	823.4	2,928.3
NEPT	427.9	379.7	385.0	298.1	405.2	250.0	396.6	508.6	339.6	3,390.7
NYIS	1,269.2	1,186.1	1,182.9	1,211.2	1,375.6	1,373.0	1,568.5	1,661.1	1,737.4	12,565.0
OVEC	226.8	304.1	619.3	474.0	586.7	719.0	980.8	2,106.3	983.2	7,000.2
TVA	129.3	207.5	212.2	255.9	230.3	473.7	1,170.7	1,129.5	539.9	4,349.0
Total	8,133.9	7,616.3	8,596.0	6,727.0	8,548.5	8,268.8	11,939.1	14,125.5	12,029.4	85,984.5

Interface Pricing

Table 4-7 Active interfaces: January through September 2011 (See 2010 SOM, Figure 4-7)

PJM 2011 Interfaces (January through September)												
	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
FE	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

Figure 4-5 PJM's footprint and its external interfaces[16] (See 2010 SOM, Figure 4-4)

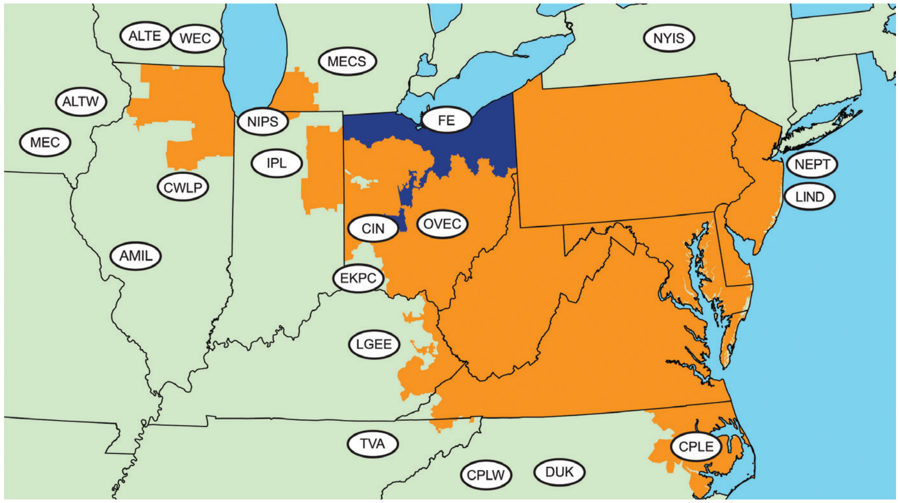


Table 4-8 Active pricing points: 2011 (See 2010 SOM, Table 4-8)

PJM 2011 Pricing Points (January through September)												
	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
MICHFE	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
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

16 The area in blue on Figure 4 5 shows the region that was incorporated with PJM as part of the ATSI integration that occurred on June 1, 2011 at 0100. Additionally, at that same time, the PJM/First Energy Corp. (FE) Interface was eliminated..

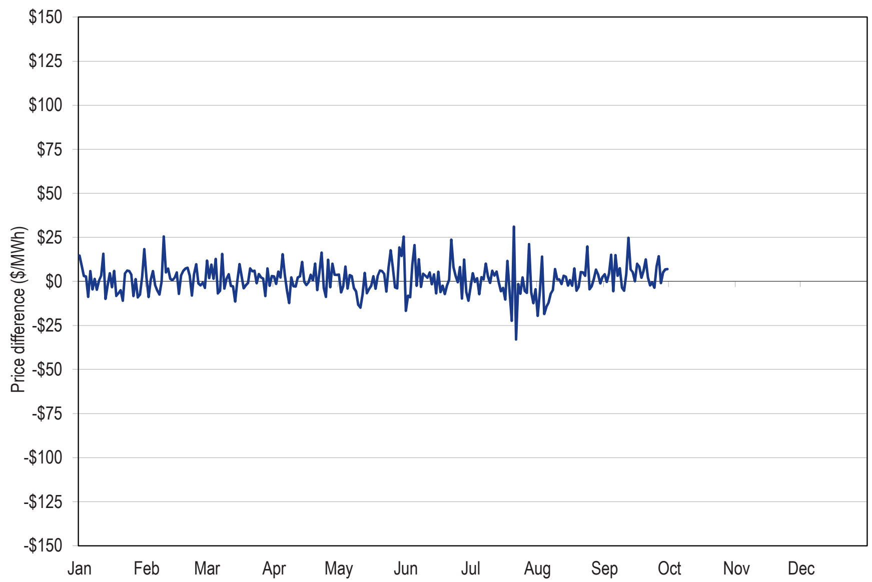
Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

PJM and MISO Interface Prices

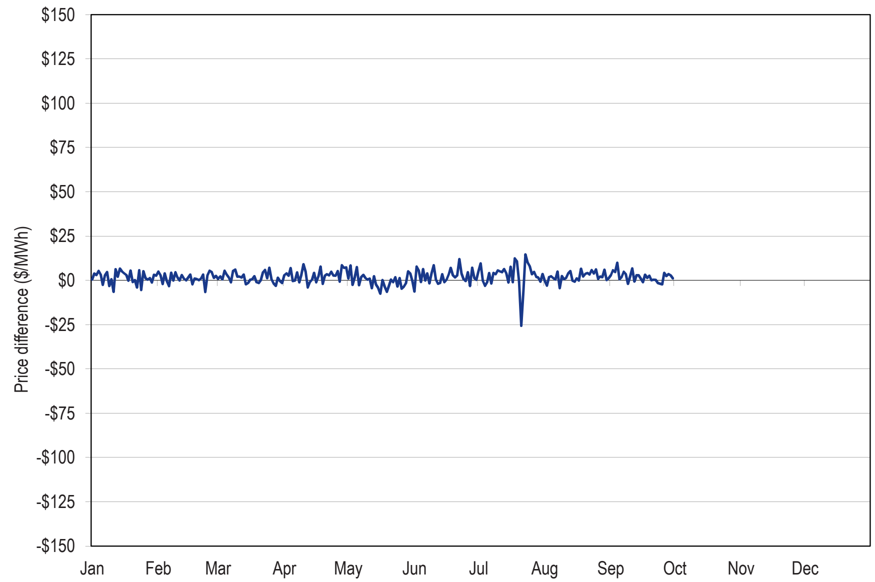
Real-Time Prices

Figure 4-6 Figure 4-6 Real-time daily hourly average price difference (MISO Interface minus PJM/MISO): January through September 2011 (See 2010 SOM, Figure 4-5)



Day-Ahead Prices

Figure 4-7 Day-ahead daily hourly average price difference (MISO interface minus PJM/MISO): January through September 2011 (See 2010 SOM, Figure 4-6)



PJM and NYISO Interface Prices

Real-Time Prices

Figure 4-8 Real-time daily hourly average price difference (NY proxy minus PJM/NYIS): January through September 2011 (See 2010 SOM, Figure 4-7)

Day-Ahead Prices

Figure 4-9 Day-ahead daily hourly average price difference (NY proxy minus PJM/NYIS): January through September 2011 (See 2010 SOM, Figure 4-8)

Summary of Interface Prices between PJM and Organized Markets

Figure 4-10 PJM, NYISO and MISO real-time border price averages: January through September 2011 (See 2010 SOM, Figure 4-9)

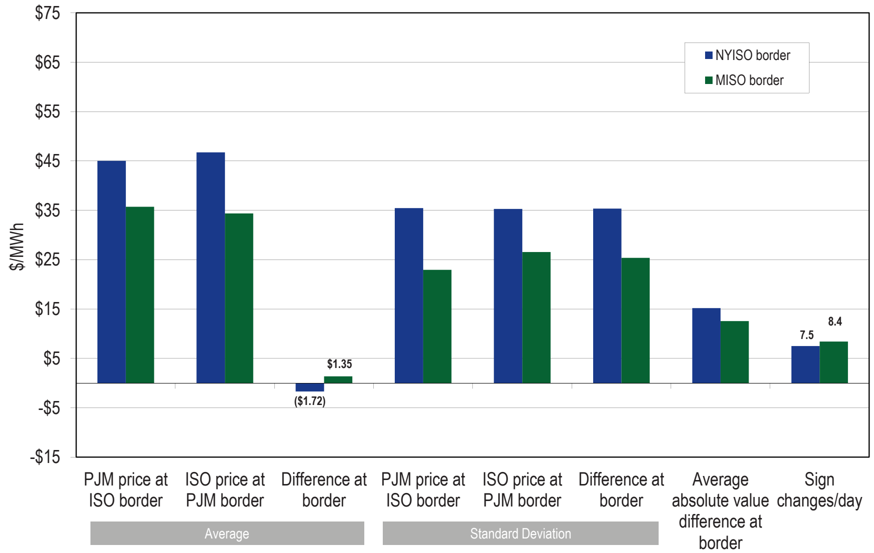
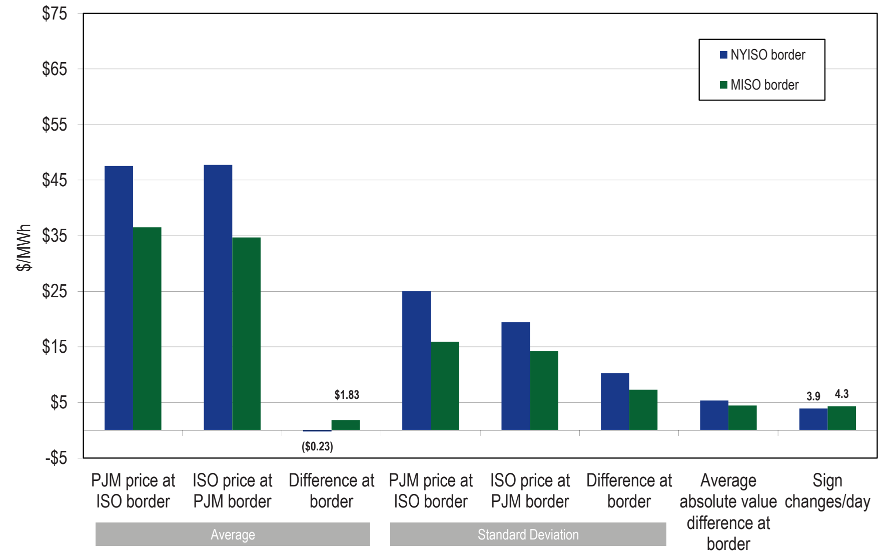
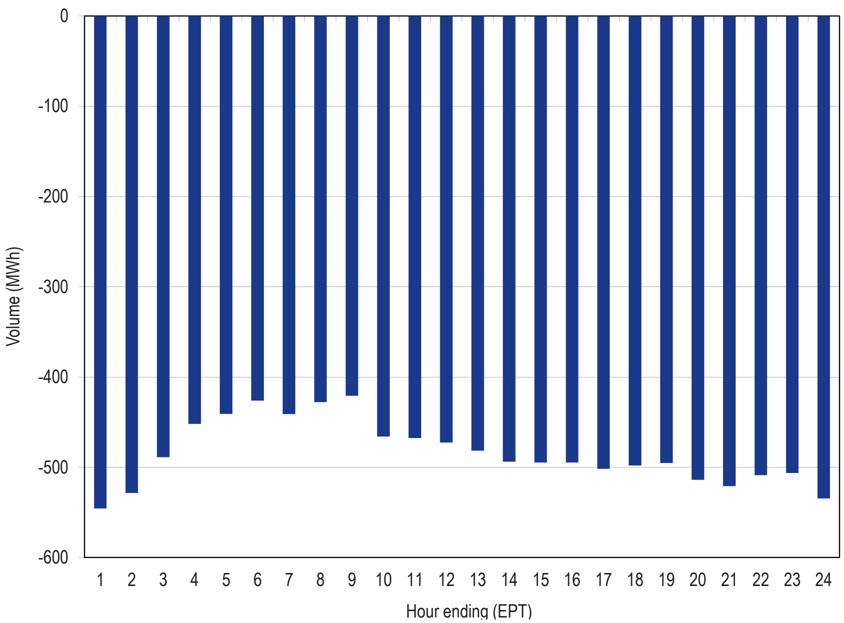


Figure 4-11 PJM, NYISO and MISO day-ahead border price averages: January through September 2011 (See 2010 SOM, Figure 4-10)



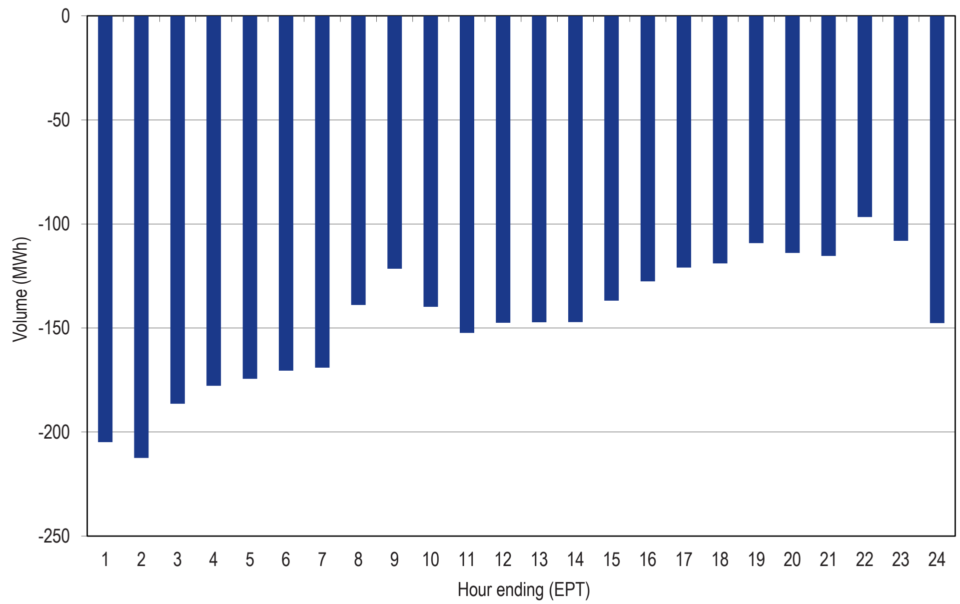
Neptune Underwater Transmission Line to Long Island, New York

Figure 4-12 Neptune hourly average flow: January through September 2011 (See 2010 SOM, Figure 4-11)



Linden Variable Frequency Transformer (VFT) facility

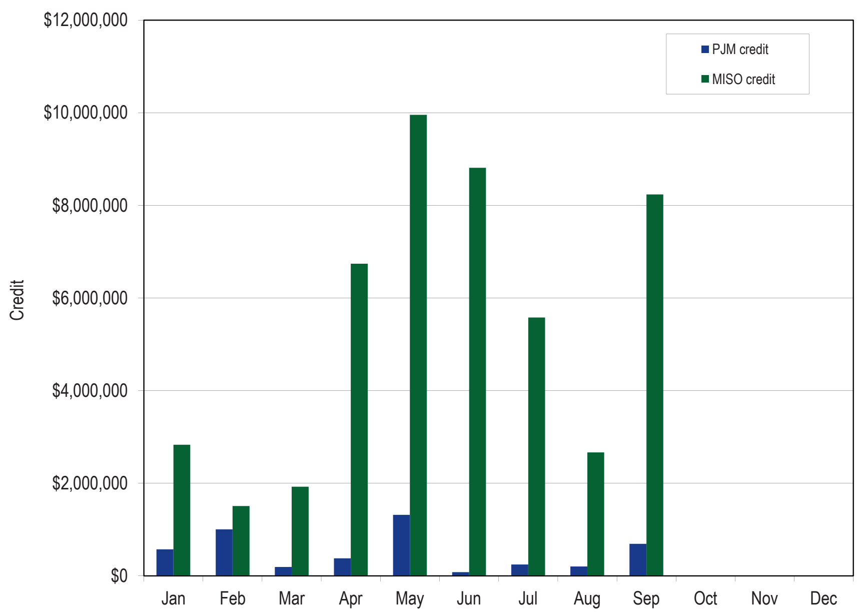
Figure 4-13 Linden hourly average flow: January through September 2011 (See 2010 SOM, Figure 4-12)



Operating Agreements with Bordering Areas

PJM and MISO Joint Operating Agreement

Figure 4-14 Credits for coordinated congestion management: January through September 2011 (See 2010 SOM, Figure 4-13)



Other Agreements/Protocols with Bordering Areas

Con Edison and PSE&G Wheeling Contracts

Table 4-9 Con Edison and PSE&G wheeling settlement data: January through September 2011 (See 2010 SOM, Table 4-9)

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	($2,115,263)	($962)	($2,116,225)	($12,053,779)	$0	($12,053,779)
Congestion Credit			$142,667			($12,246,931)
Adjustments			$15,459			$1,004,637
Net Charge			($2,274,350)			($811,484)

Interchange Transaction Issues

Loop Flows

Table 4-10 Net scheduled and actual PJM interface flows (GWh): January through September 2011 (See 2010 SOM, Table 4-10)

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	6,134	18	6,116	33,978%
CPLW	(1,456)	2	(1,458)	(72,900%)
DUK	(2,147)	(201)	(1,946)	968%
EKPC	2,208	505	1,703	337%
LGEE	984	2,734	(1,750)	(64%)
MEC	(1,678)	(4,542)	2,864	(63%)
MISO	(10,667)	(3,381)	(7,286)	215%
ALTE	(4,345)	(1,221)	(3,124)	256%
ALTW	(1,680)	(728)	(952)	131%
AMIL	7,571	(239)	7,810	(3,268%)
CIN	187	197	(10)	(5%)
CWLP	(219)	-	(219)	0%
FE	(3,464)	(1,005)	(2,459)	245%
IPL	1,174	(266)	1,440	(541%)
MECS	(11,105)	1,674	(12,779)	(763%)
NIPS	(3,107)	(619)	(2,488)	402%
WEC	4,321	(1,174)	5,495	(468%)
NYISO	(8,312)	(9,407)	1,095	(12%)
LIND	(1,011)	(951)	(60)	6%
NEPT	(3,173)	(3,173)	-	0%
NYIS	(4,128)	(5,283)	1,155	(22%)
OVEC	6,649	9,365	(2,716)	(29%)
TVA	3,761	731	3,030	415%
Total	(4,524)	(4,176)	(348)	8.3%

Loop Flows at PJM's Southern Interfaces

Figure 4-15 Southwest actual and scheduled flows: January 2006 through September 2011 (See 2010 SOM, Figure 4-14)

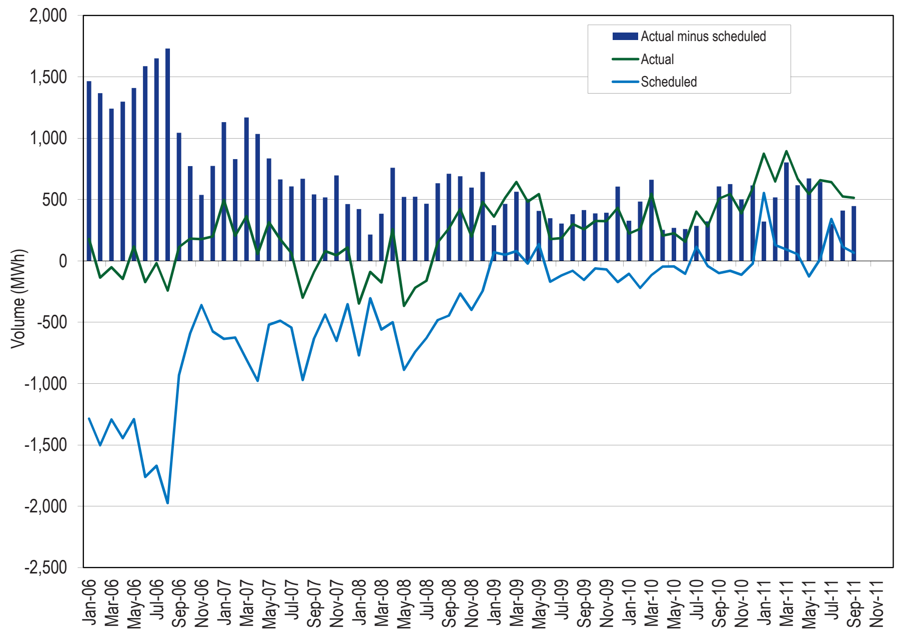
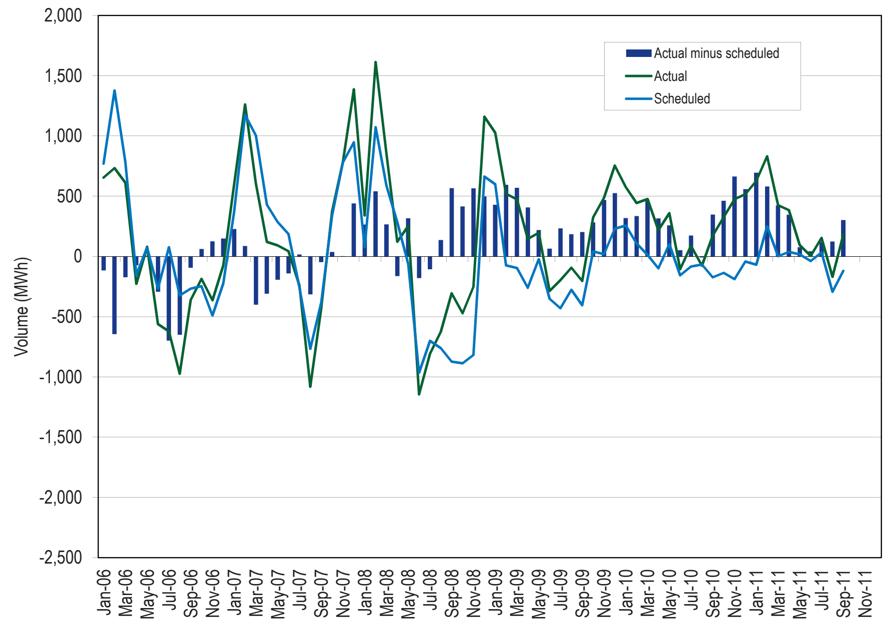


Figure 4-16 Southeast actual and scheduled flows: January 2006 through September 2011 (See 2010 SOM, Figure 4-15)



TLR Procedures

Table 4-11 Table 4-11 PJM and MISO TLR procedures: Calendar year 2010 and January through September 2011[17] (See 2010 SOM, Figure 4-16, Figure 4-17 and Figure 4-18)

	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

17 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>.

Table 4-12 Number of TLRs by TLR level by reliability coordinator: January through September 2011 (See 2010 SOM, Table 4-11)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2011	ICTE	20	11	120	39	34	0	224
	MISO	66	27	1	7	9	0	110
	NYIS	146	0	0	0	0	0	146
	ONT	79	0	0	0	0	0	79
	PJM	33	25	0	0	0	0	58
	SWPP	210	239	1	18	17	0	485
	TVA	55	71	3	1	15	0	145
	VACS	9	3	0	0	0	0	12
Total		618	376	125	65	75	0	1,259

Up-To Congestion

Figure 4-17 Monthly up-to congestion cleared bids in MWh: January 2006 through September 2011 (See 2010 SOM, Figure 4-19)

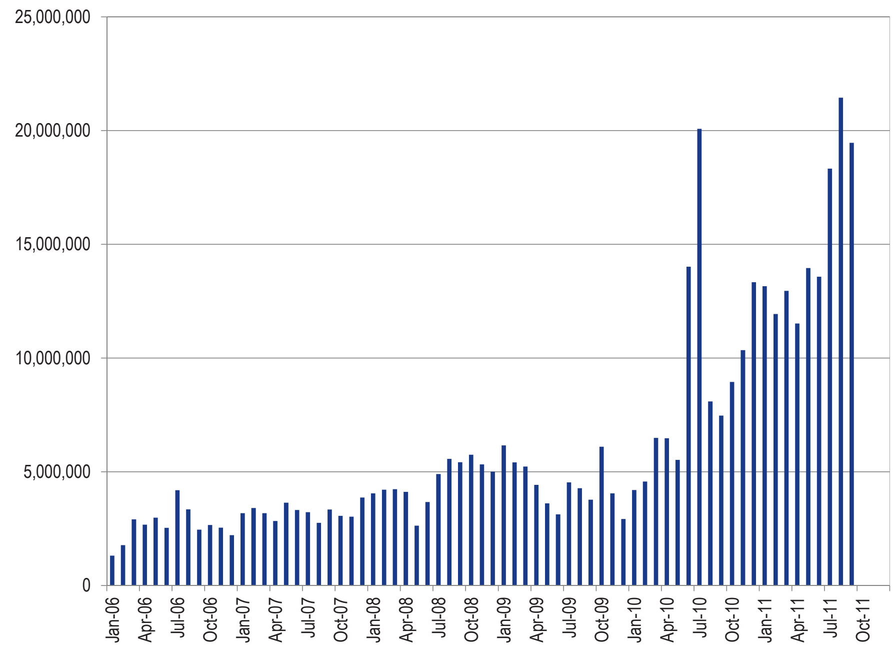


Table 4-13 Monthly volume of cleared and submitted up-to congestion bids: January, 2009, through September, 2011. (See 2010 SOM, Table 4-12)

	Bid MW				Bid Volume				Cleared MW				Cleared Volume			
Month	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total
Jan-09	4,218,910	5,787,961	319,122	10,325,993	90,277	74,826	6,042	171,145	2,591,211	3,242,491	202,854	6,036,556	56,132	45,303	4,210	105,645
Feb-09	3,580,115	4,904,467	318,440	8,803,022	64,338	70,874	6,347	141,559	2,374,734	2,836,344	203,907	5,414,985	42,101	44,423	4,402	90,926
Mar-09	3,649,978	5,164,186	258,701	9,072,865	64,714	72,495	5,531	142,740	2,285,412	2,762,459	178,507	5,226,378	42,408	42,007	4,299	88,714
Apr-09	2,607,303	5,085,912	73,931	7,767,146	47,970	67,417	2,146	117,533	1,797,302	2,582,294	48,478	4,428,074	32,088	35,987	1,581	69,656
May-09	2,196,341	4,063,887	106,860	6,367,088	40,217	54,745	1,304	96,266	1,496,396	2,040,737	77,553	3,614,686	26,274	29,720	952	56,946
Jun-09	2,598,234	3,132,478	164,903	5,895,615	47,625	44,755	2,873	95,253	1,540,169	1,500,560	88,723	3,129,452	28,565	23,307	1,522	53,394
Jul-09	3,984,680	3,776,957	296,910	8,058,547	67,039	56,770	5,183	128,992	2,465,891	1,902,807	163,129	4,531,826	41,924	31,176	2,846	75,946
Aug-09	3,551,396	4,388,435	260,184	8,200,015	64,652	64,052	3,496	132,200	2,278,431	2,172,133	194,415	4,644,978	41,774	34,576	2,421	78,771
Sep-09	2,948,353	4,179,427	156,270	7,284,050	51,006	64,103	2,405	117,514	1,774,589	2,479,898	128,344	4,382,831	31,962	40,698	1,944	74,604
Oct-09	3,172,034	6,371,230	154,825	9,698,089	46,989	100,350	2,217	149,556	2,060,371	3,931,346	110,646	6,102,363	31,634	70,964	1,672	104,270
Nov-09	3,447,356	3,851,334	103,325	7,402,015	53,067	61,906	1,236	116,209	2,065,813	1,932,595	51,929	4,050,337	33,769	32,916	653	67,338
Dec-09	2,323,383	2,502,529	66,497	4,892,409	47,099	47,223	1,430	95,752	1,532,579	1,359,936	34,419	2,926,933	31,673	28,478	793	60,944
Jan-10	3,794,946	3,097,524	212,010	7,104,480	81,604	55,921	3,371	140,896	2,250,689	1,789,018	161,977	4,201,684	49,064	33,640	2,318	85,022
Feb-10	3,841,573	3,937,880	316,150	8,095,603	80,876	80,685	2,269	163,830	2,627,101	2,435,650	287,162	5,349,913	50,958	48,008	1,812	100,778
Mar-10	4,877,732	4,454,865	277,180	9,609,777	97,149	74,568	2,239	173,956	3,209,064	3,071,712	263,516	6,544,292	60,277	48,596	2,064	110,937
Apr-10	3,877,306	5,558,718	210,545	9,646,569	67,632	85,358	1,573	154,563	2,622,113	3,690,889	170,020	6,483,022	42,635	54,510	1,154	98,299
May-10	3,800,870	5,062,272	149,589	9,012,731	74,996	78,426	1,620	155,042	2,366,149	3,049,405	112,700	5,528,253	47,505	48,996	1,112	97,613
Jun-10	9,126,963	9,568,549	1,159,407	19,854,919	95,155	89,222	6,960	191,337	6,863,803	6,850,098	1,072,759	14,786,660	59,733	55,574	5,831	121,138
Jul-10	12,818,141	11,526,089	5,420,410	29,764,640	124,929	106,145	18,948	250,022	8,971,914	8,237,557	5,241,264	22,450,734	73,232	60,822	16,526	150,580
Aug-10	8,231,393	6,767,617	888,591	15,887,601	115,043	87,876	10,664	213,583	4,430,832	2,894,314	785,726	8,110,871	62,526	40,485	8,884	111,895
Sep-10	7,768,878	7,561,624	349,147	15,679,649	184,697	161,929	4,653	351,279	3,915,814	3,110,580	256,039	7,282,433	63,405	45,264	3,393	112,062
Oct-10	8,732,546	9,795,666	476,665	19,004,877	189,748	154,741	7,384	351,873	4,150,104	4,564,039	246,594	8,960,736	76,042	65,223	3,670	144,935
Nov-10	11,636,949	9,272,885	537,369	21,447,203	253,594	170,470	9,366	433,430	5,765,905	4,312,645	275,111	10,353,661	112,250	71,378	4,045	187,673
Dec-10	17,769,014	12,863,875	923,160	31,556,049	307,716	215,897	15,074	538,687	7,851,235	5,150,286	337,157	13,338,678	136,582	93,299	7,380	237,261
Jan-11	20,275,932	11,807,379	921,120	33,004,431	351,193	210,703	17,632	579,528	7,917,986	4,925,310	315,936	13,159,232	151,753	91,557	8,417	251,727
Feb-11	18,418,511	13,071,483	800,630	32,290,624	345,227	226,292	17,634	589,153	6,806,039	4,879,207	248,573	11,933,818	151,003	99,302	8,851	259,156
Mar-11	17,330,353	12,919,960	749,276	30,999,589	408,628	274,709	15,714	699,051	7,104,642	5,603,583	275,682	12,983,906	178,620	124,990	7,760	311,370
Apr-11	17,215,352	9,321,117	954,283	27,490,752	513,881	265,334	17,459	796,674	7,452,366	3,797,819	351,984	11,602,168	229,707	113,610	8,118	351,435
May-11	21,058,071	11,204,038	2,937,898	35,200,007	562,819	304,589	24,834	892,242	8,294,422	4,701,077	1,031,519	14,027,018	261,355	143,956	11,116	416,427
Jun-11	20,455,508	12,125,806	395,833	32,977,147	524,072	285,031	12,273	821,376	7,632,235	5,361,825	198,482	13,192,543	226,747	132,744	6,363	365,854
Jul-11	24,273,892	16,837,875	409,863	41,521,630	603,519	338,810	13,781	956,110	9,585,027	8,617,284	205,599	18,407,910	283,287	186,866	7,008	477,161
Aug-11	23,790,091	21,014,941	229,895	45,034,927	591,170	403,269	8,278	1,002,717	10,594,771	10,875,384	103,141	21,573,297	274,398	208,593	3,648	486,639
Sep-11	21,740,208	18,135,378	232,626	40,108,212	526,945	377,158	7,886	911,989	10,219,806	9,270,121	82,200	19,572,127	270,088	185,585	3,444	459,117
Total	319,112,311	269,114,344	20,831,615	609,058,270	6,785,586	4,826,649	259,822	11,872,057	154,894,915	135,931,402	13,506,042	304,332,358	3,301,471	2,412,553	150,209	5,864,233

Figure 4-18 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction: January through September 2011 (See 2010 SOM, Figure 4-20)

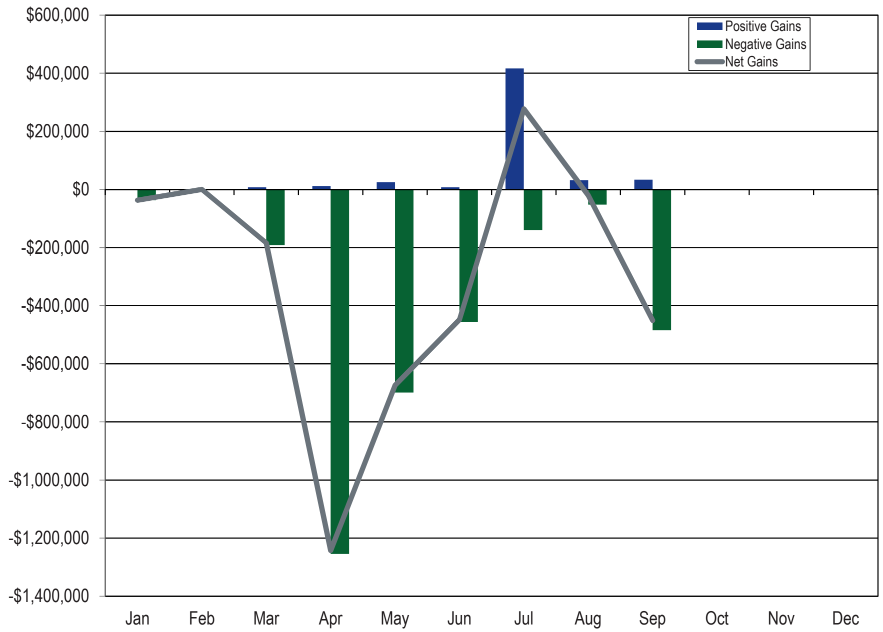
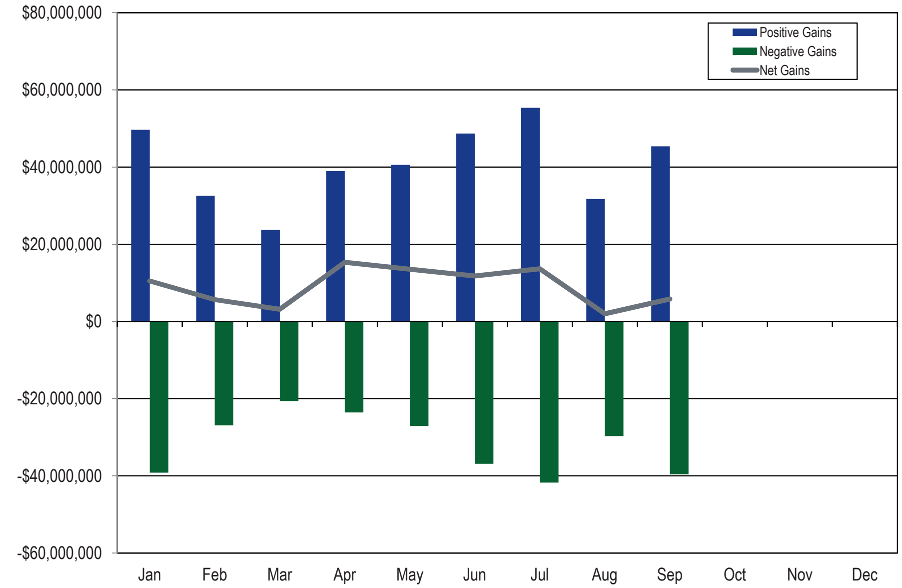


Figure 4-19 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Energy Market transaction: January through September 2011 (See 2010 SOM, Figure 4-21)



Interface Pricing Agreements with Individual Balancing Authorities

Table 4-14 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through September 2007 through 2011 (See 2010 SOM, Table 4-13)

Jan - Sep	Southeast LMP	Southwest LMP	SOUTHIIMP LMP	SOUTHEXP LMP	Difference Southeast LMP - SOUTHIMP	Difference Southwest LMP - SOUTHIMP	Difference Southeast LMP - SOUTHEXP	Difference Southwest LMP - SOUTHEXP
2007	$54.99	$45.44	$49.32	$48.56	$5.67	($3.88)	$6.44	($3.11)
2008	$67.99	$54.53	$59.19	$59.15	$8.81	($4.65)	$8.84	($4.62)
2009	$36.41	$32.05	$33.58	$33.58	$2.83	($1.54)	$2.83	($1.54)
2010	$44.30	$37.18	$40.18	$39.99	$4.12	($3.01)	$4.31	($2.81)
2011	$43.12	$38.26	$40.41	$40.41	$2.71	($2.15)	$2.71	($2.15)

Table 4-15 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through September 2011 (See 2010 SOM, Table 4-14)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.10	$42.26	$40.41	$40.41	$0.69	$1.86
PEC	$41.81	$43.95	$40.41	$40.41	$1.41	$3.54
NCMPA	$41.73	$41.92	$40.41	$40.41	$1.33	$1.52

Figure 4-20 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2011 (See 2010 SOM, Figure 4-22)

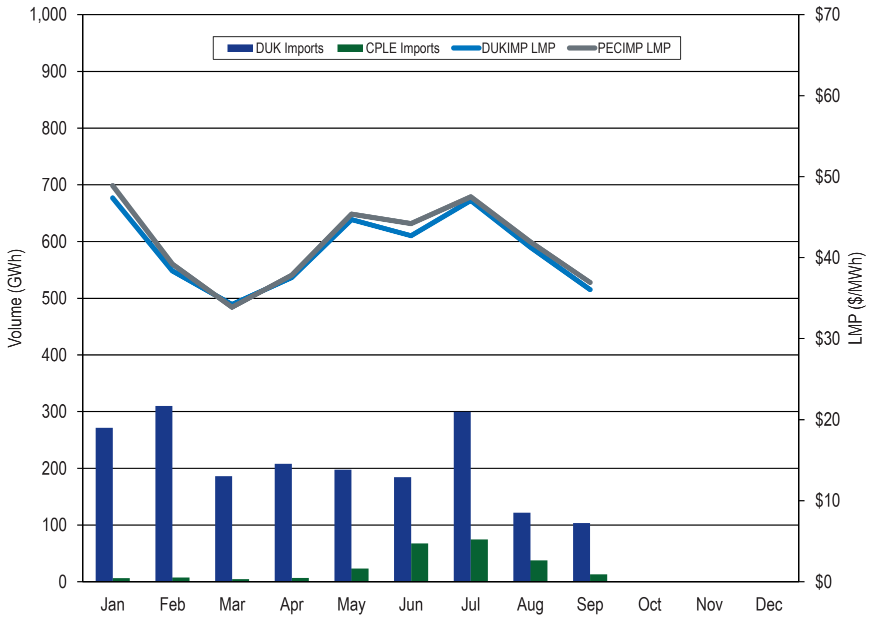


Figure 4-21 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2011 (See 2010 SOM, Figure 4-23)

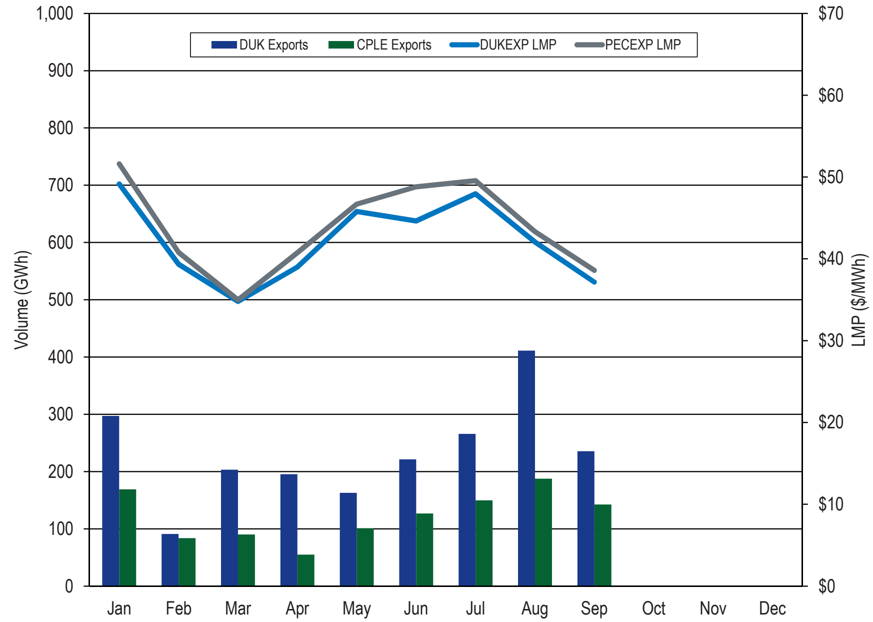


Table 4-16 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through September 2007 through 2011 (See 2010 SOM, Table 4-15)

Jan - Sep	Southeast LMP	Southwest LMP	SOUTHIIMP LMP	SOUTHEXP LMP	Difference Southeast LMP - SOUTHIMP	Difference Southwest LMP - SOUTHIMP	Difference Southeast LMP - SOUTHEXP	Difference Southwest LMP - SOUTHEXP
2007	$53.50	$45.05	$48.60	$47.68	$4.90	($3.55)	$5.82	($2.63)
2008	$68.22	$55.57	$60.09	$60.09	$8.12	($4.53)	$8.12	($4.53)
2009	$36.78	$32.20	$33.83	$33.83	$2.95	($1.63)	$2.95	($1.63)
2010	$45.33	$37.57	$40.24	$40.24	$5.09	($2.66)	$5.09	($2.66)
2011	$43.45	$38.69	$40.30	$40.30	$3.15	($1.61)	$3.15	($1.61)

Table 4-17 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through September 2011 (See 2010 SOM, Table 4-16)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.51	$43.20	$40.30	$40.30	$1.20	$2.90
PEC	$42.42	$44.99	$40.30	$40.30	$2.12	$4.68
NCMPA	$41.97	$42.59	$40.30	$40.30	$1.67	$2.28

Figure 4-22 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2011 (See 2010 SOM, Figure 4-24)

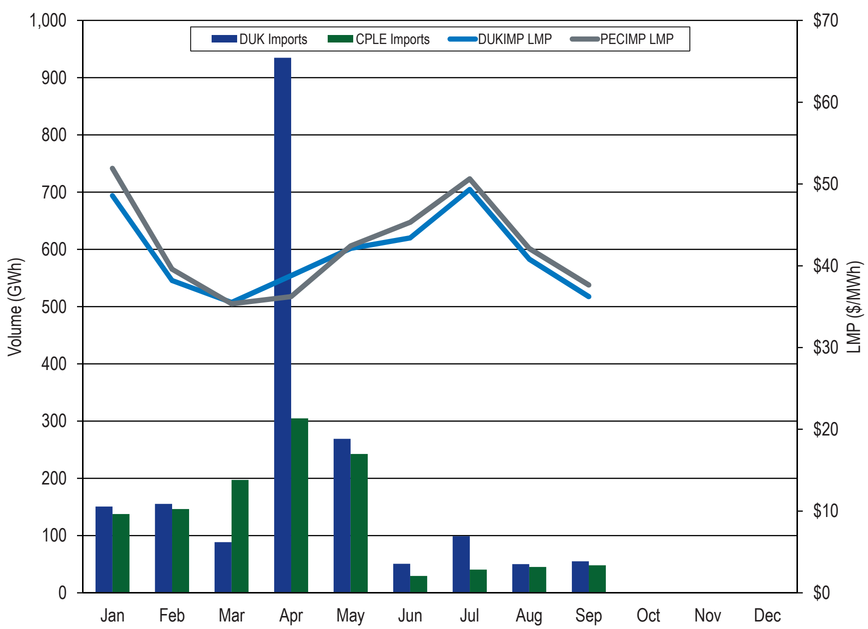
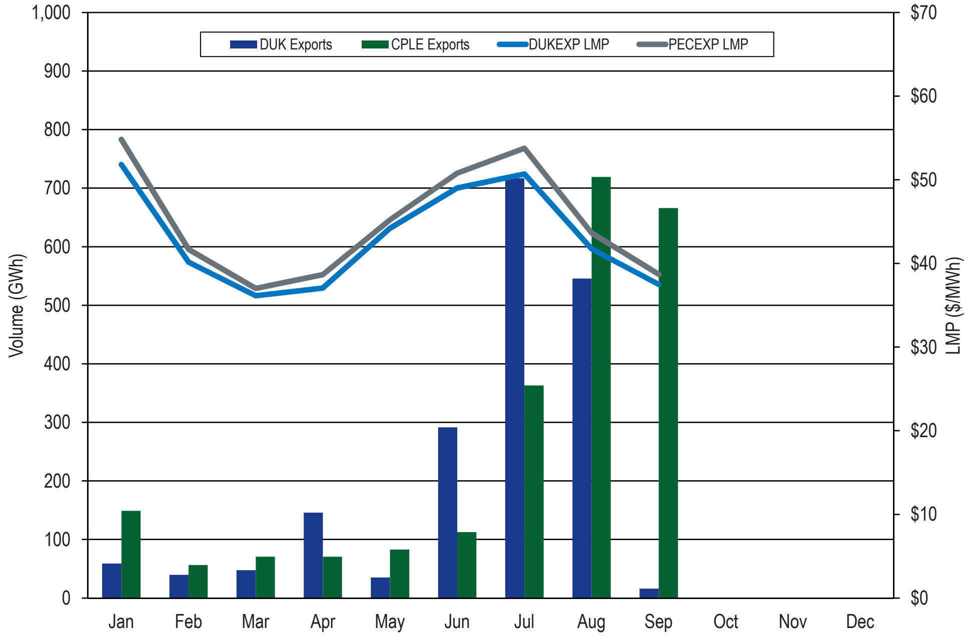


Figure 4-23 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2011 (See 2010 SOM, Figure 4-25)



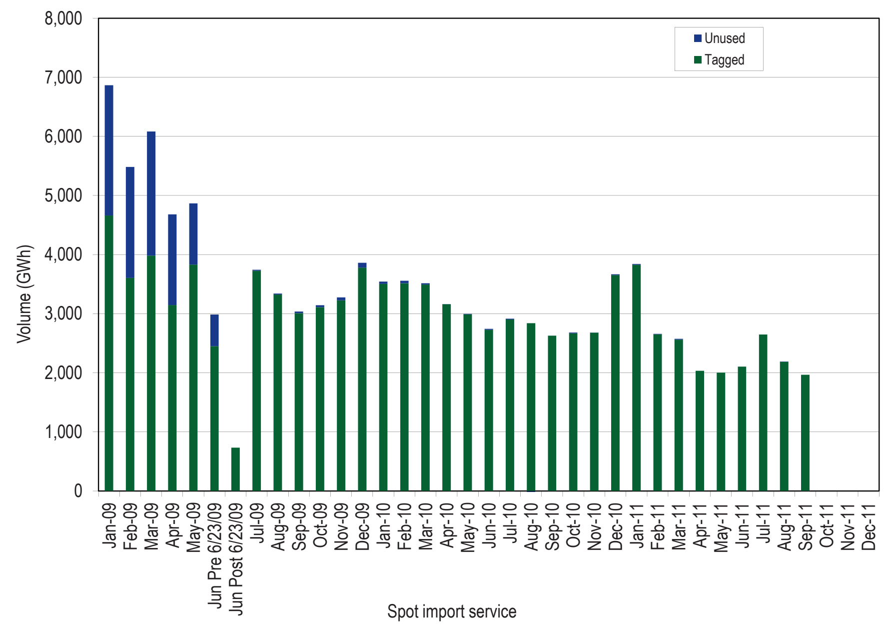
Willing to Pay Congestion and Not Willing to Pay Congestion

Table 4-18 Monthly uncollected congestion charges: Calendar year 2010 and January through September 2011 (See 2010 SOM, Figure 4-26)

Month	2010	2011
Jan	$148,764	$3,102
Feb	$542,575	$1,567
Mar	$287,417	$0
Apr	$31,255	$4,767
May	$41,025	$0
Jun	$169,197	$1,354
Jul	$827,617	$1,115
Aug	$731,539	$37
Sep	$119,162	$0
Oct	$257,448	
Nov	$30,843	
Dec	$127,176	
Total	$3,314,018	$11,942

Spot Import

Figure 4-24 Spot import service utilization: January 2009 through September 2011 (See 2010 SOM, Figure 4-27)



SECTION 5 – 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 hedge their financial obligations in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first nine months of calendar year 2011, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

Table 5-1 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. For 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.

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

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

- 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 a definition of DR which permits an inferior product to substitute for capacity.

Highlights

- The 2012/2013 RPM Second Incremental Auction and the 2013/2014 First Incremental Auction were run in the third quarter of 2011. In the 2012/2013 RPM Second Incremental Auction, the RTO resource clearing price was $13.01 per MW-day, and the EMAAC resource clearing price was $48.91 per MW-day. In the 2013/2014 RPM First Incremental Auction, the RTO resource clearing price was $20.00 per MW-day, the EMAAC resource clearing price was $178.85 per MW-day, and the SWMAAC resource clearing price was $54.82 per MW-day.

- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2014/2015 delivery year.

- Capacity in the RPM load management programs totals 9,681.0 MW for June 1, 2011.

- Annual weighted average capacity prices increased from a Capacity Credit Market (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 $127.05 per MW-day in 2014.

- Average PJM equivalent demand forced outage rate (EFORd) increased from 6.7 percent in the first nine months of 2010 to 7.6 percent in the first nine months of 2011. The increase in system EFORd resulted primarily from an increase in EFORd for steam units, offset by reductions in EFORd for combined cycle units and combustion turbine units.

- The PJM aggregate equivalent availability factor (EAF) decreased from 86.4 percent in the first nine months of 2010 to 84.8 percent in the first nine months of 2011. The equivalent maintenance outage factor (EMOF) remained constant at 2.8 percent in the first nine months of 2010 and the first nine months of 2011, the equivalent planned outage factor (EPOF) increased from 6.2 percent from the first nine months of 2010 to 7.2 percent in the first nine months of 2011, and the equivalent forced outage factor (EFOF) increased from 4.6 percent in the first nine months of 2010 to 5.2 percent in the first nine months of 2011.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

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 capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources. [1]

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

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

Market Structure

- **Supply.** Offered MW in the 2012/2013 RPM Second Incremental Auction totaled 6,448.1 MW. Offered MW in the 2013/2014 First Incremental Auction totaled 7,470.7. Effective with the 2012/2013 delivery year, PJM sell offers and buys bids are submitted in RPM Incremental Auctions as a result of changes in the RTO and LDA reliability requirements and the procurement of the Short-Term Resource Procurement Target. PJM net sell offers for the RTO in the 2012/2013 RPM Second Incremental

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2011 Quarterly State of the Market Report for PJM: January through September*, Section 5, “Capacity Market” and include all capacity within the PJM footprint.

2 See 126 FERC ¶ 61,275 (2009) at P 86.
3 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
4 See 126 FERC ¶ 61,275 (2009) at P 88.
5 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

Auction totaled 3,522.3 MW. PJM net sell offers in the 2013/2014 RPM First Incremental Auction for the RTO totaled 3,263.8 MW.

- **Demand.** Participant buy bids in the 2012/2013 RPM Second Incremental Auction totaled 11,559.9 MW. Participant buy bids in the 2013/2014 RPM First Incremental Auction totaled 16,446.1 MW. Participant buy bids are submitted to cover short positions due to deratings and EFORd increases or because participants wanted to purchase additional capacity.

- **Market Concentration.** In the 2012/2013 RPM Second Incremental Auction all participants in the RTO as well as EMAAC market failed the three pivotal supplier (TPS) market structure test.[6] In the 2013/2014 RPM First Incremental Auction all participants in the RTO, EMAAC, and SWMAAC markets failed the three pivotal supplier (TPS) market structure 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.[7,8,9]

- **Demand-Side and Energy Efficiency Resources.** 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.[10] Of the 837.8 MW of cleared capacity in the 2012/2013 RPM Second Incremental Auction, 219.9 MW were DR offers and 16.7 MW were EE offers. Of the 2,387.1 MW of cleared capacity in the 2013/2014 RPM First Incremental Auction, 520.5 MW were DR offers and 69.2 MW were EE offers.

6 Currently, there are 24 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).

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

8 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.

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

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

Market Performance

2012/2013 RPM Second Incremental Auction

- **RTO.** Participant sell offers totaled 6,448.1 MW, and PJM sell offers totaled 3,522.3 MW in the 2012/2013 RPM Second Incremental Auction. Participant buy bids totaled 11,559.9 MW in the 2012/2013 RPM Second Incremental Auction. Cleared participant sell offers in the RTO were 837.8 MW. Cleared participant buy bids in the RTO were 3,214.6 MW. Released capacity by PJM in the RTO totaled 2,376.8 MW. The RTO clearing price was $13.01 per MW-day.

  Cleared capacity resources across the entire RTO will receive a total of $6.0 million based on the unforced MW cleared and the prices in the 2012/2013 RPM Second Incremental Auction.

- **EMAAC.** Participant sell offers totaled 874.4 MW offered in EMAAC, and PJM sell offers totaled 827.2 MW in EMAAC in the 2012/2013 RPM Second Incremental Auction. Participant buy bids totaled 1,429.2 in EMAAC in the 2012/2013 RPM Second Incremental Auction. Cleared participant sell offers in EMAAC were 150.9 MW. Cleared participant buy bids in EMAAC were 454.4 MW. Released capacity by PJM in EMAAC totaled 303.5 MW. The EMAAC clearing price was $48.91 per MW-day.

2013/2014 RPM First Incremental Auction

- **RTO.** Participant sell offers totaled 7,470.7 MW, and PJM sell offers totaled 3,263.8 MW in the 2013/2014 RPM First Incremental Auction. Participant buy bids totaled 16,446.1 MW in the 2013/2014 RPM First Incremental Auction. Cleared participant sell offers in the RTO were 2,387.1 MW. Cleared participant buy bids in the RTO were 4,882.0 MW. Released capacity by PJM in the RTO totaled 2,494.9 MW. The RTO clearing price was $20.00 per MW-day.

  Cleared capacity resources across the entire RTO will receive a total of $48.4 million based on the unforced MW cleared and the prices in the 2013/2014 RPM First Incremental Auction.

- **EMAAC.** Participant sell offers totaled 1,179.7 MW in EMAAC, and PJM sell offers totaled 702.9 MW in EMAAC in the 2013/2014 RPM First Incremental Auction. Participant buy bids totaled 1,154.1 MW in EMAAC in the 2013/2014 RPM First Incremental Auction. Cleared participant sell offers in EMAAC were 532.0 MW. Cleared participant buy bids in EMAAC were 215.4 MW. Released capacity by PJM in EMAAC totaled 527.4 MW. The EMAAC clearing price was $178.85 per MW-day.

- **SWMAAC.** Participant sell offers totaled 654.6 MW in SWMAAC, and PJM sell offers totaled MW 688.5 in SWMAAC in the 2013/2014 RPM First Incremental Auction. Participant buy bids totaled 482.0 MW in SWMAAC in the 2013/2014 RPM First Incremental Auction. Cleared participant sell offers in SWMAAC were 7.1 MW. Cleared participant buy bids in SWMAAC were 439.3 MW. Released capacity by PJM in SWMAAC totaled 323.5 MW. The SWMAAC clearing price was $54.82 per MW-day.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd increased from 6.7 percent in the first nine months of 2010 to 7.6 percent in the first nine months of 2011.[11]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 86.4 percent in the first nine months of 2010 to 84.8 percent in the first nine months of 2011.

- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (NERC) criteria, an outage may be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. In the first nine months of 2011, 10.5 percent of forced outages are 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.

11 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 nine months ending September 30, as downloaded from the PJM GADS database on October 21, 2011. 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.

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, will retire. Demand is almost entirely inelastic, because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

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

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 the first nine months of calendar year 2011. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first nine months of calendar year 2011.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[12,13,14,15] In 2011, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

Table 5-2 RPM Related MMU Reports, 2011 (New Table)

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/Reports/2011/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>

12 See "Analysis of the 2011/2012 RPM Auction Revised" (October 1, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf>.

13 See "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>.

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

15 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results" (October 4, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf>.

RPM Capacity Market

Market Structure

Supply

Table 5-3 RPM generation capacity additions: 2007/2008 through 2014/2015 (See 2010 SOM, Table 5-3)

	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	499.5	1,096.7	2,708.0
Total	7,088.9	858.7	5,404.8	5,222.8	18,575.2

Market Concentration

Preliminary Market Structure Screen

Table 5-4 Preliminary market structure screen results: 2011/2012 through 2014/2015 RPM Auctions (See 2010 SOM, Table 5-5)

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

Auction Market Structure

Table 5-5 RSI results: 2011/2012 through 2014/2015 RPM Auctions[16] (See 2010 SOM, Table 5-6)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First Incremental Auction			
RTO	0.62	30	30
2011/2012 ATSI FRR Integration Auction			
RTO	0.07	21	21
2011/2012 Third Incremental Auction			
RTO	0.41	52	52
2012/2013 BRA			
RTO	0.63	98	98
MAAC/SWMAAC	0.54	15	15
EMAAC/PSEG	7.03	6	0
PSEG North	0.00	2	2
DPL South	0.00	3	3
2012/2013 ATSI FRR Integration Auction			
RTO	0.10	16	16
2012/2013 First Incremental Auction			
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.60	25	25
EMAAC	0.00	2	2
2012/2013 Second Inremental Auction			
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.64	33	33
EMAAC	0.00	2	2
2013/2014 BRA			
RTO	0.59	87	87
MAAC/SWMAAC	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.00	2	2
Pepco	0.00	1	1
2013/2014 First Incremental Auction			
RTO/MAAC	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.00	3	3
SWMAAC/Pepco	0.00	0	0
2014/2015 BRA			
RTO	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.03	7	0
PSEG North	0.00	1	1

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

Demand-Side Resources

Table 5-6 RPM load management statistics by LDA: June 1, 2010 to June 1, 2014[17,18] (See 2010 SOM, Table 5-8)

	UCAP (MW)					
	RTO	MAAC	EMAAC	DPL South	PSEG North	Pepco
DR cleared	962.9			14.9		
DR net replacements	(516.3)			(14.9)		
ILR	8,236.4			97.2		
RPM load management @ 01-June-2010	8,683.0			97.2		
DR cleared	1,826.6					
EE cleared	76.4					
DR net replacements	(1,260.2)					
EE net replacements	0.2					
ILR certified	9,038.0					
RPM load management @ 01-June-2011	9,681.0					
DR cleared	7,744.6	4,939.9	1,836.5	97.2	121.9	
EE cleared	585.6	187.5	27.6	0.0	1.2	
DR net replacements	0.0	0.0	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-June-2012	8,330.2	5,127.4	1,864.1	97.2	123.1	
DR cleared	9,802.4	6,005.2	2,588.4			547.8
EE cleared	748.6	204.5	55.2			36.7
DR net replacements	0.0	0.0	0.0			0.0
EE net replacements	0.0	0.0	0.0			0.0
RPM load management @ 01-June-2013	10,551.0	6,209.7	2,643.6			584.5
DR cleared	14,118.4	7,236.8			443.3	
EE cleared	822.1	199.6			0.0	
DR net replacements	0.0	0.0			0.0	
EE net replacements	0.0	0.0			0.0	
RPM load management @ 01-June-2014	14,940.5	7,436.4			443.3	

17 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.

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

Table 5-7 RPM load management cleared capacity and ILR: 2007/2008 through 2014/2015[19,20] (See 2010 SOM, Table 5-9)

	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	8,735.9	9,038.0
2012/2013	7,499.3	7,744.6	567.5	585.6	0.0	0.0
2013/2014	9,487.2	9,802.4	726.3	748.6	0.0	0.0
2014/2015	13,663.8	14,118.4	796.9	822.1	0.0	0.0

Table 5-8 RPM load management statistics: June 1, 2007 to June 1, 2014[21,22] (See 2010 SOM, Table 5-10)

	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)
1-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
1-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
1-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
1-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
1-Jun-11	10,575.9	10,941.0	(1,218.1)	(1,260.2)	0.2	0.2	9,358.0	9,681.0
1-Jun-12	8,066.8	8,330.2	0.0	0.0	0.0	0.0	8,066.8	8,330.2
1-Jun-13	10,213.5	10,551.0	0.0	0.0	0.0	0.0	10,213.5	10,551.0
1-Jun-14	14,460.7	14,940.5	0.0	0.0	0.0	0.0	14,460.7	14,940.5

19 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.
20 FRR committed load management resources are not included in this table.
21 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.
22 FRR committed load management resources are not included in this table.

Market Performance

Table 5-9 Capacity prices: 2007/2008 through 2014/2015 RPM Auctions (See 2010 SOM, Table 5-14)

		RPM Clearing Price ($ per MW-day)							
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11
2008/2009 Third 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
2011/2012 Third Incremental Auction		$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
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$13.01
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$54.82
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50

Table 5-10 RPM revenue by type: 2007/2008 through 2014/2015[23,24] (See 2010 SOM, Table 5-15)

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$263,534,711	$551,453,434	$666,313,051	$1,703,980,980
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,334,802	$20,680,368	$38,571,074	$70,726,056
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,115,246	$31,191,272	$178,063,746	$653,501,083
Coal existing	$1,022,372,301	$1,844,120,476	$2,417,576,805	$2,662,434,386	$1,595,707,479	$1,015,994,058	$1,736,326,997	$1,827,519,210	$14,122,051,712
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,413,749	$12,493,918	$56,917,305	$110,177,869
Gas existing	$1,514,681,896	$1,951,345,311	$2,329,209,917	$2,632,336,161	$1,607,317,731	$1,116,743,821	$1,894,356,673	$2,003,810,846	$15,049,802,356
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$76,551,231	$166,414,514	$184,029,455	$626,902,467
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,085,726	$308,742,213	$328,877,767	$2,399,748,544
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$17,520	$6,591,114	$6,620,031
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,367	$1,346,024,263	$1,459,911,217	$10,283,710,009
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$448,034,948	$532,432,515	$663,370,167	$623,141,070	$368,084,004	$385,951,817	$620,740,652	$433,317,895	$4,075,073,068
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$3,896,120	$28,160,593
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,837,739	$43,613,120	$34,529,047	$276,391,712
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$469,425	$2,411,690	$1,190,758	$5,270,804
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$1,235,710	$2,521,159	$2,371,155	$6,195,001
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,372,110	$1,491,563	$10,190,033
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$4,998,533	$12,898,748	$30,987,962	$83,791,175
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,335,087,023	$3,869,582,961	$6,756,928,604	$7,258,389,284	$49,512,293,493

23 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.
24 The results for the ATSI Integrations Auctions are not included in this table.

Figure 5-1 History of capacity prices: Calendar year 1999 through 2014[25] (See 2010 SOM, Figure 5-1)

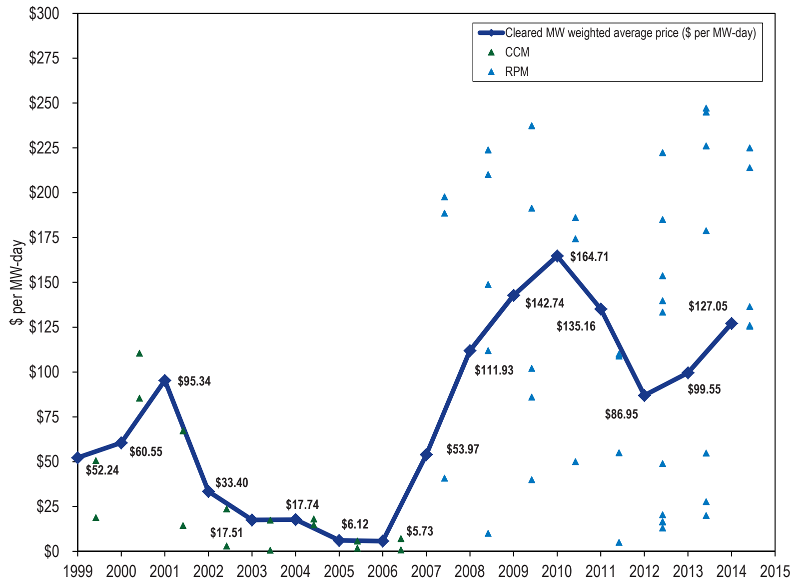


Table 5-11 RPM cost to load: 2011/2012 through 2014/2015[26,27,28] (See 2010 SOM, Table 5-16)

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2011/2012			
RTO	$116.16	133,815.3	$5,689,098,601
2012/2013			
RTO	$16.52	67,621.8	$407,745,930
MAAC	$131.48	30,942.6	$1,484,941,563
EMAAC	$141.00	20,476.2	$1,053,813,160
DPL	$169.18	4,584.1	$283,077,133
PSEG	$155.47	12,087.7	$685,916,676
2013/2014			
RTO	$27.86	84,109.2	$855,298,445
MAAC	$227.11	15,244.6	$1,263,707,018
EMAAC	$245.33	37,751.5	$3,380,476,376
SWMAAC	$226.15	8,281.8	$683,617,638
Pepco	$239.36	7,861.0	$686,785,528
2014/2015			
RTO	$125.94	84,581.3	$3,888,042,879
MAAC	$135.25	52,277.4	$2,580,741,594
DPL	$142.99	4,615.4	$240,881,412
PSEG	$164.00	12,208.7	$730,811,202

25 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2014 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.

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

27 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.

28 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 2012/2013, 2013/2014, and 2014/2015 Net Load Prices are not finalized. The 2012/2013, 2013/2014, and 2014/2015 Obligation MW are not finalized.

Generator Performance

Generator Performance Factors

Figure 5-2 PJM equivalent outage and availability factors: January through September 2007 to 2011 (See 2010 SOM, Figure 5-4)

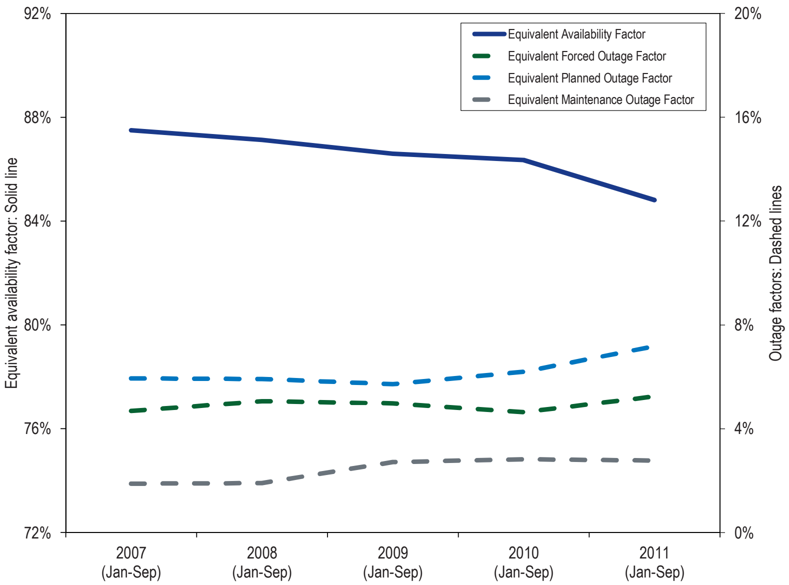
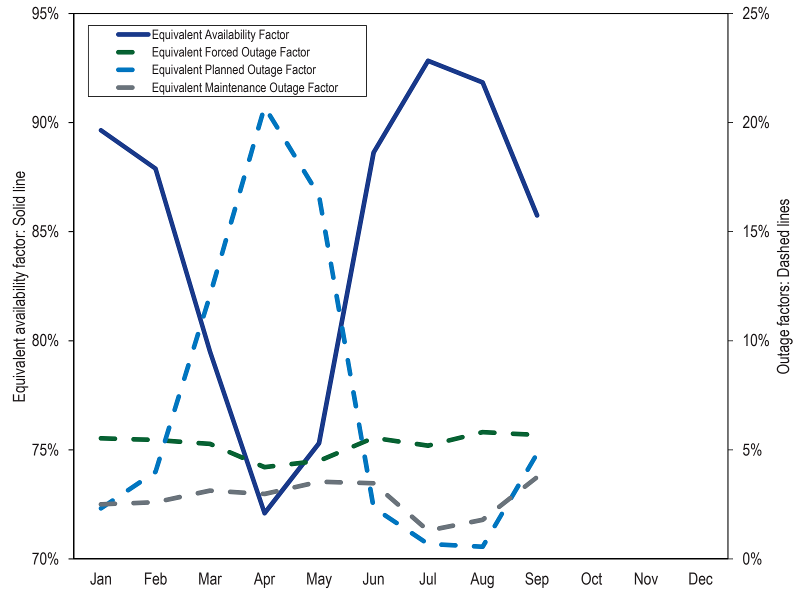
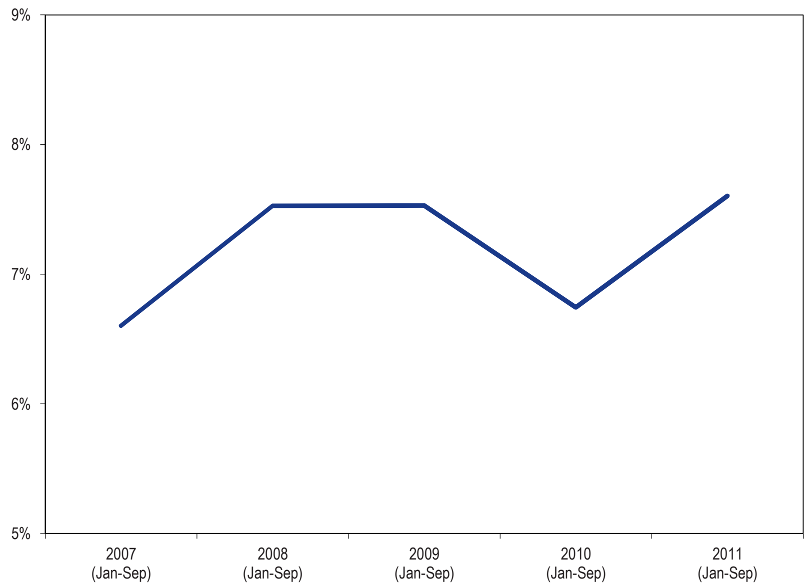


Figure 5-3 Generator performance factors: January through September 2011 (See 2010 SOM, Figure 5-10)



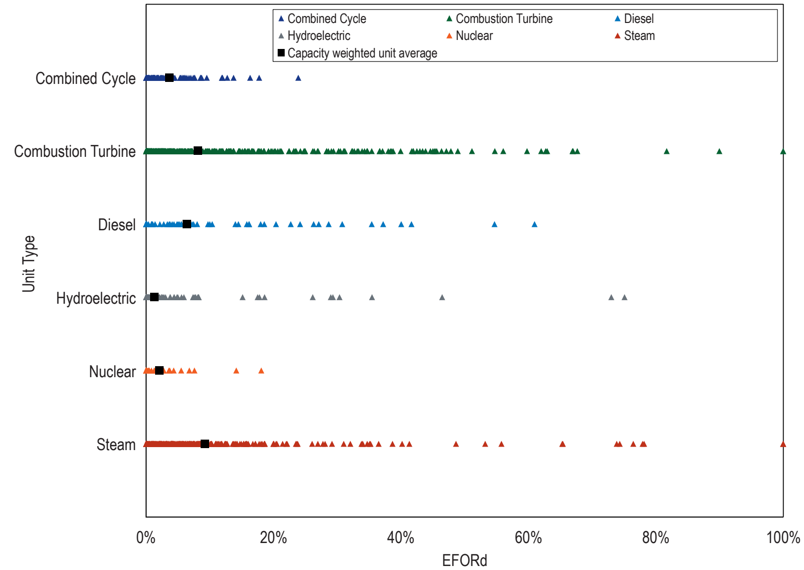
Generator Forced Outage Rates

Figure 5-4 Trends in the PJM equivalent demand forced outage rate (EFORd): January through September 2007 to 2011 (See 2010 SOM, Figure 5-5)



Distribution of EFORd

Figure 5-5 Distribution of EFORd data by unit type: January through September 2011 (See 2010 SOM, Figure 5-6)



Components of EFORd

Table 5-12 PJM EFORd data: January through September 2007 to 2011 (See 2010 SOM, Table 5-20)

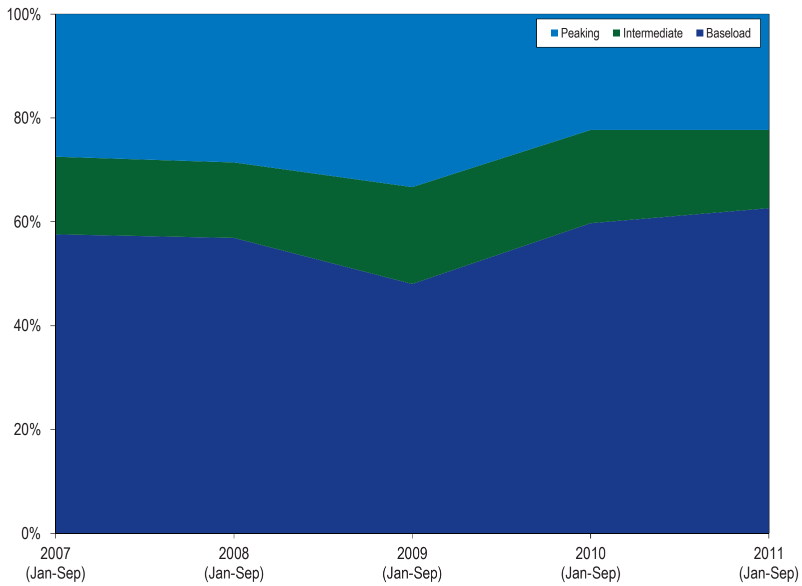
	2007 (Jan-Sep)	2008 (Jan-Sep)	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)
Combined Cycle	3.3%	3.5%	4.5%	3.7%	2.9%
Combustion Turbine	10.6%	10.7%	8.7%	8.2%	7.5%
Diesel	12.5%	11.0%	8.8%	6.4%	9.7%
Hydroelectric	2.0%	2.5%	2.7%	1.3%	2.3%
Nuclear	1.2%	1.0%	4.3%	2.1%	2.3%
Steam	8.6%	10.4%	9.5%	9.3%	11.1%
Total	6.6%	7.5%	7.5%	6.7%	7.6%

Table 5-13 Contribution to EFORd for specific unit types (Percentage points): January through September 2007 to 2011[29] (See 2010 SOM, Figure 5-21)

	2007 (Jan-Sep)	2008 (Jan-Sep)	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	Change in 2011 from 2010
Combined Cycle	0.4	0.4	0.5	0.5	0.3	(0.1)
Combustion Turbine	1.7	1.7	1.4	1.3	1.2	(0.1)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.1	0.1	0.0
Nuclear	0.2	0.2	0.8	0.4	0.4	0.0
Steam	4.2	5.1	4.7	4.5	5.5	1.0
Total	6.6	7.5	7.5	6.7	7.6	0.9

Duty Cycle and EFORd

Figure 5-6 Contribution to EFORd by duty cycle: January through September 2007 to 2011 (See 2010 SOM, Figure 5-7)



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

Forced Outage Analysis

Table 5-14 Contribution to EFOF by unit type by cause: January through September 2011 (See 2010 SOM, Table 5-22)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	4.9%	0.0%	0.0%	0.0%	0.0%	24.9%	20.5%
Boiler Piping System	17.6%	0.0%	0.0%	0.0%	0.0%	7.1%	6.6%
Economic	0.9%	4.3%	0.3%	3.7%	0.0%	7.3%	6.3%
Electrical	13.7%	14.8%	7.9%	18.5%	9.3%	4.6%	6.1%
Generator	2.5%	0.6%	0.6%	2.2%	0.0%	6.5%	5.4%
Boiler Air and Gas Systems	0.2%	0.0%	0.0%	0.0%	0.0%	5.9%	4.8%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	5.0%	4.1%
Feedwater System	2.9%	0.0%	0.0%	0.0%	1.3%	4.4%	3.8%
Circulating Water Systems	4.5%	0.0%	0.0%	0.0%	12.3%	2.7%	3.3%
Catastrophe	0.9%	1.6%	11.8%	24.7%	30.3%	0.8%	3.3%
Miscellaneous (Generator)	11.9%	4.5%	0.8%	3.3%	2.7%	1.3%	2.2%
Fuel Quality	0.0%	0.0%	1.5%	0.0%	0.0%	2.4%	1.9%
Reserve Shutdown	3.0%	13.9%	1.0%	0.6%	0.5%	1.1%	1.8%
Auxiliary Systems	3.9%	16.7%	0.0%	0.2%	0.0%	0.8%	1.7%
Condensing System	2.0%	0.0%	0.0%	0.0%	1.5%	1.7%	1.6%
Cooling System	0.1%	0.0%	0.2%	8.5%	2.3%	1.6%	1.5%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.5%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	20.7%	0.0%	1.5%
Miscellaneous (Steam Turbine)	2.3%	0.0%	0.0%	0.0%	0.4%	1.5%	1.4%
All Other Causes	28.2%	43.5%	75.8%	38.3%	18.7%	18.6%	20.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-15 Contributions to Economic Outages: January through September 2011 (See 2010 SOM, Table 5-23)

	Contribution to Economic Reasons
Lack of fuel (OMC)	96.8%
Lack of fuel (Non-OMC)	1.6%
Lack of water (Hydro)	0.7%
Other economic problems	0.6%
Fuel conservation	0.2%
Total	100.0%

Table 5-16 Contribution to EFOF by unit type: January through September 2011 (See 2010 SOM, Table 5-24)

	EFOF	Contribution to EFOF
Combined Cycle	2.7%	4.9%
Combustion Turbine	1.8%	5.4%
Diesel	4.4%	0.2%
Hydroelectric	0.8%	1.1%
Nuclear	1.9%	7.1%
Steam	7.4%	81.3%
Total	4.6%	100.0%

Outages Deemed Outside Management Control

Table 5-17 OMC Outages: January through September 2011 (See 2010 SOM, Table 5-25)

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Economic	58.1%	6.1%
Catastrophe	31.0%	3.3%
Electrical	6.2%	0.7%
Miscellaneous (External)	2.3%	0.2%
Power Station Switchyard	1.9%	0.2%
Regulatory	0.4%	0.0%
Fuel Quality	0.0%	0.0%
Total	100.0%	10.5%

Table 5-18 PJM EFORd vs. XEFORd: January through September 2011 (See 2010 SOM, Table 5-26)

	EFORd	XEFORd	Difference
Combined Cycle	2.9%	2.7%	0.2%
Combustion Turbine	7.5%	6.5%	1.1%
Diesel	9.7%	3.6%	6.1%
Hydroelectric	2.3%	1.7%	0.5%
Nuclear	2.3%	1.7%	0.7%
Steam	11.1%	10.1%	1.0%
Total	7.6%	6.8%	0.9%

Components of EFORp

Table 5-19 Contribution to EFORp by unit type (Percentage points): January through September 2010 and 2011 (See 2010 SOM, Table 5-27)

	2010 (Jan-Sep)	2011 (Jan-Sep)
Combined Cycle	0.4	0.2
Combustion Turbine	0.5	0.5
Diesel	0.0	0.0
Hydroelectric	0.0	0.1
Nuclear	0.5	0.4
Steam	3.7	3.5
Total	5.1	4.7

Table 5-20 PJM EFORp data by unit type: January through September 2010 and 2011 (See 2010 SOM, Table 5-28)

	2010 (Jan-Sep)	2011 (Jan-Sep)
Combined Cycle	3.0%	1.6%
Combustion Turbine	2.9%	3.4%
Diesel	3.5%	2.1%
Hydroelectric	1.1%	2.0%
Nuclear	2.9%	2.0%
Steam	7.6%	6.9%
Total	5.1%	4.7%

EFORd, XEFORd and EFORp

Table 5-21 Contribution to PJM EFORd, XEFORd and EFORp by unit type: January through September 2011 (See 2010 SOM, Table 5-29)

	EFORd	XEFORd	EFORp
Combined Cycle	0.3	0.3	0.2
Combustion Turbine	1.2	1.0	0.5
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1
Nuclear	0.4	0.3	0.4
Steam	5.5	5.0	3.5
Total	7.6	6.8	4.7

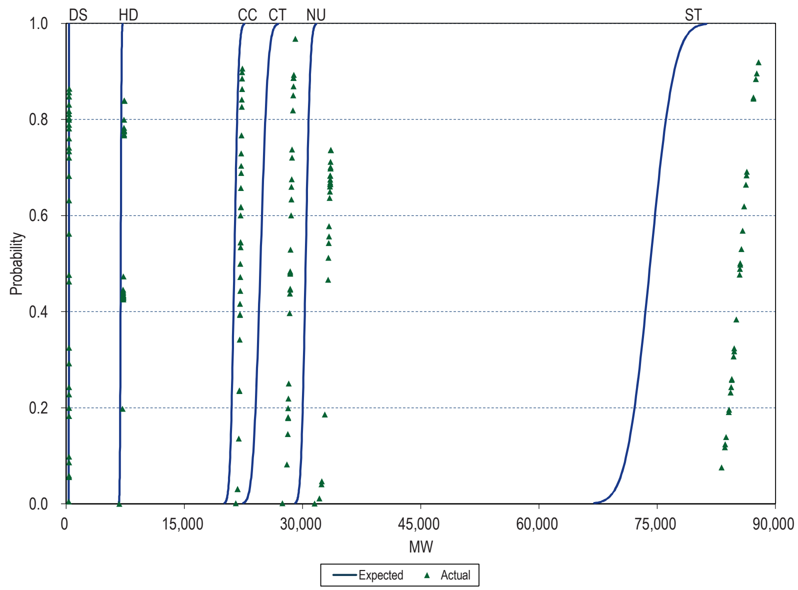
Table 5-22 PJM EFORd, XEFORd and EFORp data by unit type: January through September 2011[30] (See 2010 SOM, Table 5-30)

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	2.9%	2.7%	1.6%	0.2%	1.3%
Combustion Turbine	7.5%	6.5%	3.4%	1.1%	4.1%
Diesel	9.7%	3.6%	2.1%	6.1%	7.6%
Hydroelectric	2.3%	1.7%	2.0%	0.5%	0.3%
Nuclear	2.3%	1.7%	2.0%	0.7%	0.3%
Steam	11.1%	10.1%	6.9%	1.0%	4.1%
Total	7.6%	6.8%	4.7%	0.9%	3.0%

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

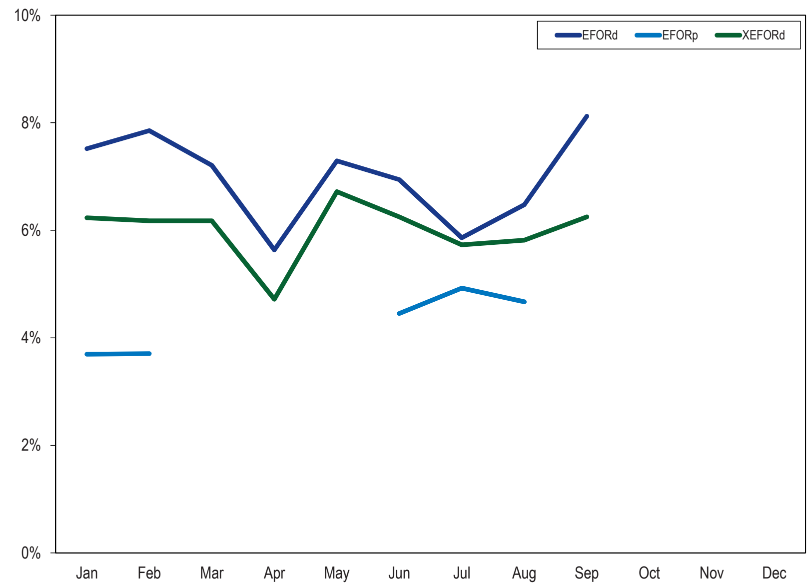
Comparison of Expected and Actual Performance

Figure 5-7 Distribution of EFORd data by unit type: January through September 2011 (See 2010 SOM, Figure 5-8)



Performance by Month

Figure 5-8 EFORd, XEFORd and EFORp: January through September 2011 (See 2010 SOM, Figure 5-9)



SECTION 6 - ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 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.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., 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.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared 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, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See the *2010 State of the Market Report for PJM*, Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2011.

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.[3]

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 Markets, and the PJM DASR Market for the first nine months of 2011.

Table 6-1 The Regulation Market results were not competitive[4]

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 91 percent of the hours in the first nine months of 2011.

- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal

3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

4 As Table 6-1 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 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. 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.

supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.

- Market performance was evaluated as not competitive, despite competitive participant behavior, because the 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.

- Market design was evaluated as flawed 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 are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 6-2 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 and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 56 percent of the hours in the first nine months of 2011.

- 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 6-3 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 the market failed the three pivotal supplier test in only a limited number of hours.

- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, about ten 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 should be added to the market to ensure that market power cannot be exercised at times of system stress.

Highlights

- The load weighted average Regulation Market clearing price, including opportunity cost, for the first nine months of 2011 was $17.03 per MW.[5] This was a decrease of $2.25, or 12 percent, from the average price for regulation during the same period in 2010. The total cost of regulation decreased by $1.21 from $33.92 per MW for the first nine months of 2010, to $32.71, or 3.6 percent. For the first nine months of 2011 the load weighted Regulation Market clearing price was only 52 percent of the total regulation cost per MW, compared to 57 percent of the total costs of regulation per MW in the first nine months of 2010.

- The load weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was $12.00 per MW in the first nine months of 2011, a $0.49 per MW increase from the same period in 2010.[6] The total cost of synchronized reserves per MWh for the first nine months of 2011 was $14.21, a 4.0 percent decrease from

5 The term "load weighted" in the Regulation Market refers to regulation MW weighted.
6 The term "load weighted" in the Synchronized Reserve Market refers to synchronized reserve MW weighted.

the total cost of synchronized reserves ($14.81) during the first nine months of 2010. The load weighted average Synchronized Reserve Market clearing price was 73 percent of the load weighted average total cost per MW of synchronized reserve in the first nine months of 2011, up from 70 percent in the same time period of 2010.

- The load weighted DASR market clearing price in the first nine months of 2011 was $1.04 per MW. In the first nine months of 2010, the load weighted price of DASR was $0.18 per MW. The year over year increase in the load weighted average price per MW of DASR was attributable to several days of high DASR prices in June, July and August.

- Black start zonal charges in the first nine months of 2011 ranged from $0.02 per MW in the ATSI zone to $0.75 per MW in the PSEG zone.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations. The additional recommendation from the *2011 Quarterly State of the Market Report for PJM: January through June*, that the Synchronized Reserve Market design be modified to address the issue of units which offer and clear synchronized reserve but fail to provide synchronized reserve when an actual spinning event occurs, also remains an MMU recommendation.

Overview

Regulation Market

The PJM Regulation Market in the first nine months of 2011 continued to be operated as a single market. There have been no structural changes since December 1, 2008, when PJM implemented four changes to the Regulation Market: introducing the three pivotal supplier test for market power; increasing the margin for cost-based regulation offers; modifying the calculation of lost opportunity cost (LOC); and terminating the offset of regulation revenues against operating reserve credits.[7]

7 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 *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Market Structure

- **Supply.** In the first nine months of 2011, the supply of offered and eligible regulation in PJM was both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in the first nine months of 2011. The ratio of offered and eligible regulation to regulation required averaged 2.95 for the first nine months of 2011. This is a 3.1 percent increase over the first nine months of 2010 when the ratio was 2.86.

- **Demand.** The on-peak regulation requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand for the first nine months of 2011 was 943 MW (856 MW off peak, and 1039 MW on peak). This is a 30 MW increase in the average hourly regulation demand for the first nine months of 2010 (830 MW off peak, and 1008 MW on peak).

  Of the LSEs' obligation to provide regulation during the first nine months of 2011, 84 percent was purchased in the spot market, 13 percent was self scheduled, and three percent was purchased bilaterally.

- **Market Concentration.** During the first nine months of 2011, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1645 which is classified as "moderately concentrated."[8] The minimum hourly HHI was 818 and the maximum hourly HHI was 3683. The largest hourly market share in any single hour was 58 percent, and 84 percent of all hours had a maximum market share greater than 20 percent.[9] In the first nine months of 2011, 91 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The MMU concludes from these results that the PJM Regulation Market in the first nine months of 2011 was characterized by structural market power in 91 percent of the hours.

8 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," 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.

9 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.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. Cost based offers apply for the entire day and are subject to validation using unit specific parameters submitted with the offer. All price based offers remain subject to the $100 per MWh offer cap.[10] In computing the market solution, PJM calculates a unit specific opportunity cost based on forecast LMP, and adds it to each offer. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the Regulation Market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. The offers of all units of owners who fail the three pivotal supplier test for an hour are capped at the lesser of their cost based or price based offer. The Regulation Market is then cleared again.

Market Performance

- **Price.** The load weighted Regulation Market clearing price for the PJM Regulation Market in the first nine months of 2011 was $17.03 per MW. This was a decrease of $2.25, or 12 percent, from the average price for regulation during the same period in 2010. The total cost of regulation decreased by $1.21 from $33.92 per MW for the first nine months of 2010, to $32.71, or 3.6 percent. For the first nine months of 2001 the load weighted Regulation Market clearing price was only 52 percent of the total regulation cost per MW, compared to 57 percent of the total costs of regulation per MW in the first nine months of 2010. This change was primarily the result of using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of regulation include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP.

  The difference between the total cost of regulation and the clearing price of regulation was primarily the result of using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of regulation include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP. In addition, units scheduled to regulate are, at times, switched with other units in an owner's fleet of regulation units by the owner or at the direction of PJM Dispatch as a result of binding constraints or performance problems.

10 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 46 (June 1, 2011) p. 55.

Synchronized Reserve Market

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

The integration of the Trans-Allegheny Line (TrAIL)[11] project (performed in three stages April 8, May 13, and May 20, 2011) resulted in a change to the interface defining the Mid-Atlantic subzone of the RFC Synchronized Reserve Market. That interface had been the AP South interface since March 2009. [12] After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface. This change is being made to PJM's Manual 11, Energy and Ancillary Services Market Operations and was made in the software that clears the regulation and synchronized reserve markets at the end of September. From May 20, 2011, through the end of September the percent of Tier 1 synchronized reserve available west of the interface that is also available in the Mid-Atlantic subzone (transfer capacity) was set to 30 percent. PJM is currently studying the Synchronized Reserve Market to see if the transfer capacity needs further adjustment after the change to Bedington—Black Oak as the Mid-Atlantic Subzone interface. The more Tier 1 synchronized reserve available, the less Tier 2 synchronized reserve needs to be cleared. These changes to the transfer interface capacity did affect the Synchronized Reserve Market by changing the amount of Tier 2 required in the Mid Atlantic Subzone. Synchronized reserves added out of market were 2.5 percent of all synchronized reserves during the first nine months of 2011, down from 4.1 percent for the same time period in 2010. After-market opportunity cost payments accounted for 25 percent of total costs during the first nine months of 2011 compared to 28 percent for the first nine months of 2010.

In December of 2010, PJM Market Operations changed the transfer capacity across the AP South interface from 15 percent of available Tier 1

11 <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/trail.aspx>
12 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 46 (June 1, 2011) p. 67.

to five percent.[13] Less Tier 1 synchronized reserve available means more Tier 2 synchronized reserve is required in the Mid-Atlantic Subzone in order to satisfy the 1,300 MW requirement. This resulted in significant increases in scheduled Tier 2 synchronized reserves in the Mid-Atlantic Subzone Synchronized Reserve market from January through May 2011. PJM has kept the Tier 1 synchronized reserve transfer capacity at 30 percent since early June.

Market Structure

- **Supply.** In the first nine months of 2011 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 low cost, and their participation in this market lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve to synchronized reserve required was 1.09 for the Mid-Atlantic Subzone.[14] This is an 11 percent decrease from first nine months of 2010 when the ratio was 1.23. The ratio of offered and eligible synchronized reserve was 3.09 for the RFC Zone. This is a 15 percent increase from the first nine months of 2010 when the ratio was 2.69. 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.** PJM made several changes to the hourly required synchronized reserve requirements between December, 2008 and September, 2011 (Table 6-16). The synchronized reserve requirement in the RFC zone was raised to 1,700 MW on February 9 and 10, 2011 for double spinning, and was raised to 1,760 MW on May 3, 4, 5 and 6 for double spinning. On September 7 the Synchronized Reserve requirement was raised to 1,700 MW for most of the day for double spinning. Table 6-20 lists all spinning events from January 2009 through September 2011. Although providers of Tier 2 synchronized reserve are paid for making synchronized reserve MW available every hour, it is only during spinning events that such Tier 2 synchronized reserve is actually used. Because the number of hours when a spinning event occurs is small compared to the number of hours a synchronized reserve market is cleared, adequate reductions in payments should apply to providers who clear the market but provide less synchronized reserve MW during spinning events than they are paid for.

  For the first nine months of 2011, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 79 percent of hours. In the first nine months of 2010 a Tier 2 synchronized reserve market was cleared in 64 percent of hours. For the first nine months of 2011, the average required Tier 2 synchronized reserve (including self scheduled) was 562 MW. For the first nine months of 2010 the average required Tier 2 synchronized reserve was 312 MW. The Tier 2 requirement for January through March 2011 was 756 MW but only 346 MW for April through September 2011. This drop was primarily because the TrAIL line increased the transfer capacity of the most constraining interface allowing more Tier 1 to be available in the Mid Atlantic Subzone. The full impact of TrAIL on the amount of Tier 1 synchronized reserve available across the Bedington—Black Oak constraint is still being studied and may result in further changes to the transfer capability.

  Synchronized reserves added out of market were two and a half percent of all Mid-Atlantic Subzone synchronized reserves in the first nine months of 2011. Synchronized reserves added out of market were four percent of all Mid-Atlantic Subzone synchronized reserves in the first nine months of 2010.

- Market demand for Tier 2 is less than the requirement for synchronized reserve by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, less than one percent (16 hours) cleared a Tier 2 Synchronized Reserve Market in the RFC during the first nine months of 2011. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone in 20 hours during the first nine months of 2011.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone for the first nine months of 2011 was 2768, which is classified as "highly concentrated."[15] For purchased synchronized reserve (cleared plus added) the HHI was 2816. In the first nine months of 2011, 51 percent of hours had a maximum market share greater than 40 percent, compared to 40 percent of hours in the same period of 2010.

  In the Mid-Atlantic Subzone, in the first nine months of 2011, 56 percent of hours that cleared a synchronized reserve market had three or fewer

13 See the *2010 State of the Market Report for PJM*, Section 6, "Ancillary Service Markets", p. 452.

14 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

15 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

pivotal suppliers. In the same period of 2010, 36 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Subzone Synchronized Reserve Market in the first nine months of 2011 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 LMP forecasts, 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.

  Total MW of cleared demand side resources increased in the first nine months of 2011 over the first nine months of 2010 (from 392,783 MW to 623,918 MW) but their share of the total Synchronized Reserve Market declined from 32 percent to 29 percent. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in seven percent of hours in the first nine months of 2011 compared to nine percent of hours on the first nine months of 2010.

- **Compliance.** There is a compliance issue in the Synchronized Reserve Market. A substantial proportion of synchronized reserves which clear the market fail to provide their full amount of synchronized reserve when an actual spinning event occurs. The penalty structure is adequate to address this behavior.[16] The problem is that the penalty structure permits egregious non-compliance, a situation in which providers do not comply at all or at a very low (less than 30 percent) level. The penalty structure is inadequate to address this behavior. The MMU recommends that the Synchronized Reserve Market design, including compliance monitoring and non-compliance penalties, be restructured to address this issue and provide stronger incentives for compliance.

Market Performance

- **Price.** The load weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $12.00 per MW in the first nine months of 2011, a $0.49 per MW increase from the same period in 2010. The total cost of synchronized reserves per MWh for the first nine months of 2011 was $14.21, a 4.0 percent decrease from the total cost of synchronized reserves ($14.81) during the first nine months of 2010. The market clearing price was 73 percent of the total synchronized reserve cost per MW in the first nine months of 2011, up from 70 percent in the same time period of 2010.

  The difference between the total cost of synchronized reserve and the clearing price of synchronized reserve was largely the result of using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of synchronized reserve include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP.

- **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 the first nine months of 2011.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[17] 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.[18] 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

- **Concentration.** In the first nine months of 2011, there were 21 hours in the DASR market which failed the three pivotal supplier test. All 21 hours occurred in June, July and August during periods of high demand. The current structure of PJM's DASR Market does not include

16 See PJM. "Manual 11, Energy and Ancillary Services Market Operations, 4.2.1.3 Non-Performance", Rev. 46 (June 1, 2011), p. 75

17 See 117 FERC ¶ 61,331 (2006).

18 See PJM. "Manual 13: Emergency Operations," Revision 44, (May 26, 2011); pp 11-12.

the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

- **Demand.** In the first nine months of 2011, the required DASR was 7.11 percent of peak load forecast, up from 6.88 percent in the same time period for 2010.[19] The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2010 the load forecast error declined from 1.90 percent to 1.87 percent. The forced outage rate increased from 4.98 percent to 5.23 percent. Added together the 2011 DASR requirement is now 7.11 percent. The DASR MW purchased averaged 6,622 MW per hour for the first nine months of 2011, an increase from 6,176 MW per hour during the same period in 2010.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market, but the nature of economic withholding in the DASR Market changed in June. The first five months of 2011 continued the pattern that has existed since the inception of the DASR Market in which five percent of units offered at $50 or more and four percent offered at more than $900. Most of these offers were reduced during the month of June but remained at levels exceeding competitive levels. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[20] Units that do not offer have their offers set to zero, the incremental cost of providing DASR. The marginal cost of providing DASR is zero. As of June 2011, 17 percent of units offering into the DASR market are offering at $5.00 or more.

- **DSR.** Demand side resources do participate in the DASR Market, but no demand resource cleared the DASR Market in the first nine months of 2011.

Market Performance

- **Price.** The load weighted DASR market clearing price in the first nine months of 2011 was $1.04 per MW. In the first nine months of 2010, the load weighted price of DASR was $0.18 per MW. The year over year increase in the load weighted average price per MW of DASR was attributable to several days of high DASR prices in June, July and August. 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. In 45 percent of hours from January through September the DASR Market Clearing Price was $0.00. Most, 97 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 = $108.92) of hours 99.7 percent of the price is determined by opportunity cost. For the bottom 99.5 percent (average clearing price = $0.20) of hours only two percent of the price is composed of LOC (Figure 6-15).

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 with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[21]

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.

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. For the first nine months of 2011, charges were $10.02 million. This is 37 percent higher than the first nine months of 2010, when total black start service charges were $7.29 million. There was substantial zonal variation. The increased cost of black start in 2011 is primarily attributable to updated Schedule 6A (to the OATT) rates for all units. The increased Schedule 6A rates included net cost of new entry, VOM, bond rates, and oil forward strip.

Black start zonal charges in the first nine months of 2011 ranged from $0.02 per MW in the ATSI zone to $0.75 per MW in the PSEG zone. Black start costs in the BGE zone increased due to major refurbishments of multiple

19 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
20 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 46 (June 1, 2011), p. 124.
21 OATT Schedule 1 § 1.3BB.

black start resources. The black start resources were identified as critical assets in BGE's black start restoration plan by PJM and the transmission owner. The resources undergoing major refurbishment through the black start process are recovering capital investment costs to maintain the units as black start resources using the capital recovery factor (CRF) from Schedule 6A rather than the standard incentive rate provided in the tariff for black start resources. During the recovery period the unit's annual Black Start capital cost recovery will be limited to the greater of the black start payments or capacity market revenues.[22]

Ancillary Services costs per MW of load: 2001 - 2011

Table 6-4 shows PJM ancillary services costs from January through September for 2001 through 2011 on a per MW of load basis. The Scheduling, System Control, and Dispatch category of costs is comprised of PJM Scheduling, PJM System Control and PJM Dispatch; Owner Scheduling, Owner System Control and Owner Dispatch; Other Supporting Facilities; Black Start Services; Direct Assignment Facilities; and Reliability*First* Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

Table 6-4 History of ancillary services costs per MW of Load: January through September of 2001 through 2011 (See 2010 SOM, Table 6-4)

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001 (Jan-Sep)	$0.55	$0.43	$0.22	$0.00	$1.18
2002 (Jan-Sep)	$0.47	$0.52	$0.21	$0.00	$0.66
2003 (Jan-Sep)	$0.53	$0.59	$0.23	$0.09	$0.88
2004 (Jan-Sep)	$0.50	$0.64	$0.25	$0.14	$0.90
2005 (Jan-Sep)	$0.78	$0.47	$0.25	$0.11	$0.88
2006 (Jan-Sep)	$0.55	$0.48	$0.28	$0.07	$0.44
2007 (Jan-Sep)	$0.65	$0.47	$0.29	$0.06	$0.58
2008 (Jan-Sep)	$0.75	$0.34	$0.29	$0.07	$0.55
2009 (Jan-Sep)	$0.36	$0.36	$0.36	$0.05	$0.47
2010 (Jan-Sep)	$0.37	$0.38	$0.36	$0.06	$0.75
2011 (Jan-Sep)	$0.35	$0.36	$0.39	$0.09	$0.87

22 <http://www.pjm.com/~/media/committees-groups/task-forces/bsstf/20100420/20100420-automated-formula-rate-adjustment-process.ashx>

Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.[23] The Regulation Market results are not competitive because the 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.

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 is recommending that the rules for compliance be reevaluated.

The MMU concludes that the DASR Market results were competitive in the first nine months of 2011, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

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

Overall, the MMU concludes that the Regulation Market results were not competitive in the first nine months of 2011 as a result of the identified

23 The *2009 State of the Market Report for PJM* provided the basis for this recommendation. 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."

market design changes and their implementation. This conclusion is not the result of participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in the first nine months of 2011. The MMU concludes that the DASR Market results were competitive in the first nine months of 2011.

Regulation Market

Market Structure

Supply

Table 6-5 PJM regulation capability, daily offer[24] and hourly eligible: January through September 2011 (See 2010 SOM, Table 6-5)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percentage of Capability Eligible
All Hours	8,808	5,970	68%	2,742	31%
Off Peak	8,808			2,462	28%
On Peak	8,808			3,051	35%

Demand

Table 6-6 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through September 2011 (See 2010 SOM, Table 6-6)

Month	Average Required Regulation (MW)	Ratio of Supply to Requirement
Jan	960	3.19
Feb	897	3.06
Mar	823	3.02
Apr	747	2.87
May	786	2.84
Jun	1,037	2.81
Jul	1,214	2.79
Aug	1,093	2.83
Sep	922	2.74

24 Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.

Market Concentration

Table 6-7 PJM cleared regulation HHI: January through September 2011 (See 2010 SOM, Table 6-7)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation	818	1645	3683

Figure 6-1 PJM Regulation Market HHI distribution: January through September 2011 (See 2010 SOM, Figure 6-1)

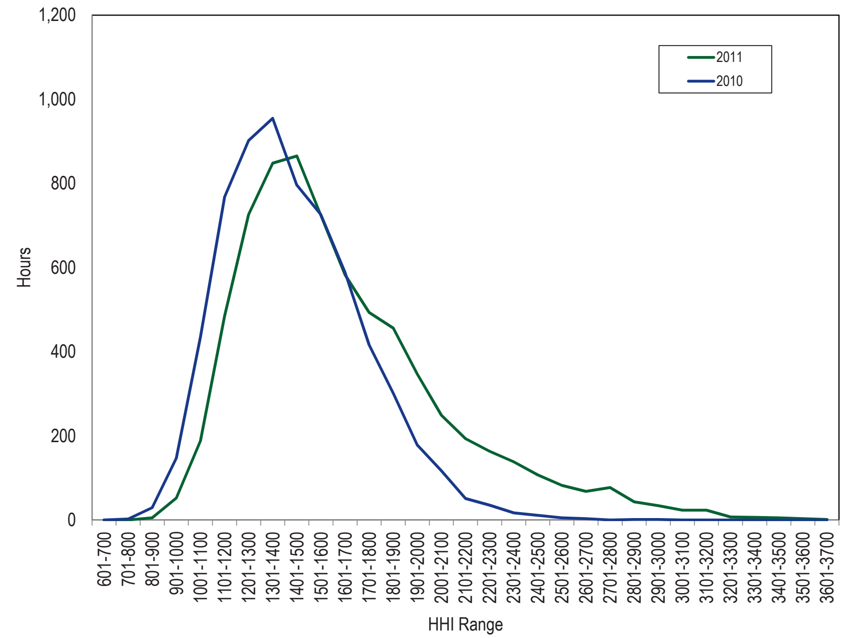


Table 6-8 Highest annual average hourly Regulation Market shares: January through September, 2011 (See 2010 SOM, Table 6-8)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	22%
2	17%
3	15%
4	10%
5	9%

Table 6-9 Regulation market monthly three pivotal supplier results: January through September, 2011 (See 2010 SOM, Table 6-9)

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	88%
Feb	87%
Mar	89%
Apr	92%
May	87%
Jun	89%
Jul	89%
Aug	83%
Sep	87%

Market Conduct

Offers

Figure 6-2 Off peak and on peak regulation levels: January through September, 2011 (See 2010 SOM, Figure 6-2)

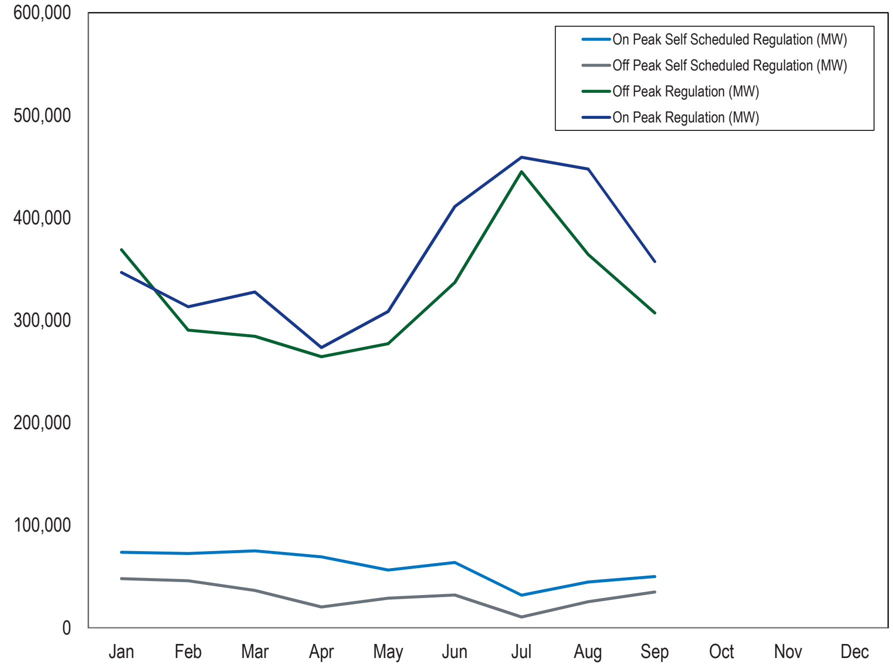


Table 6-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through September, 2011 (See 2010 SOM, Table 6-10)

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)
Jan	576,029	116,421	16,670
Feb	462,394	114,568	17,553
Mar	463,708	107,791	28,109
Apr	418,890	86,402	18,273
May	469,104	81,357	15,978
Jun	586,661	89,878	15,127
Jul	756,218	38,791	15,647
Aug	721,498	67,841	14,442
Sep	565,935	81,239	15,063

Market Performance

Price

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): January through September, 2011 (See 2010 SOM, Figure 6-3)

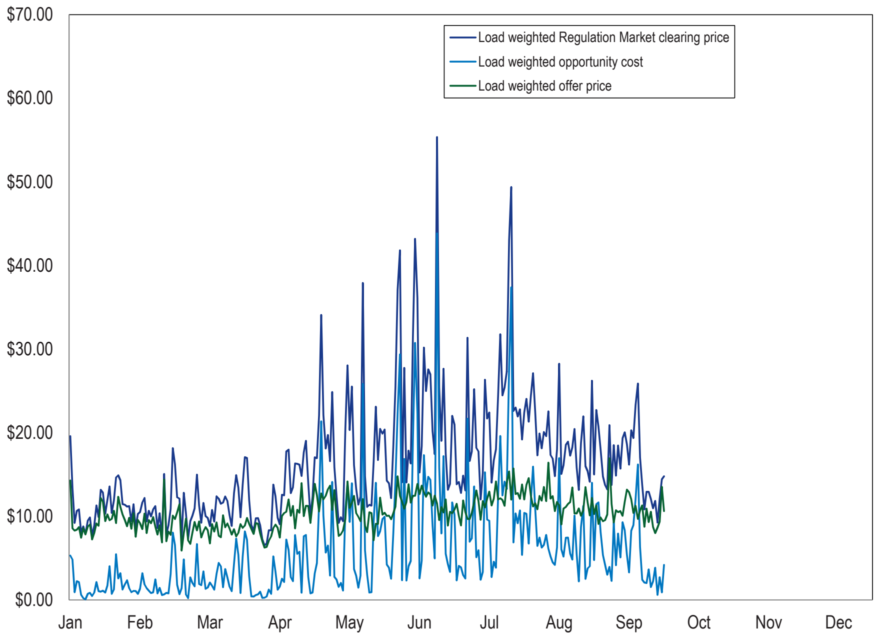


Figure 6-4 Monthly average regulation demand (required) vs. price: January through September, 2011 (See 2010 SOM, Figure 6-4)

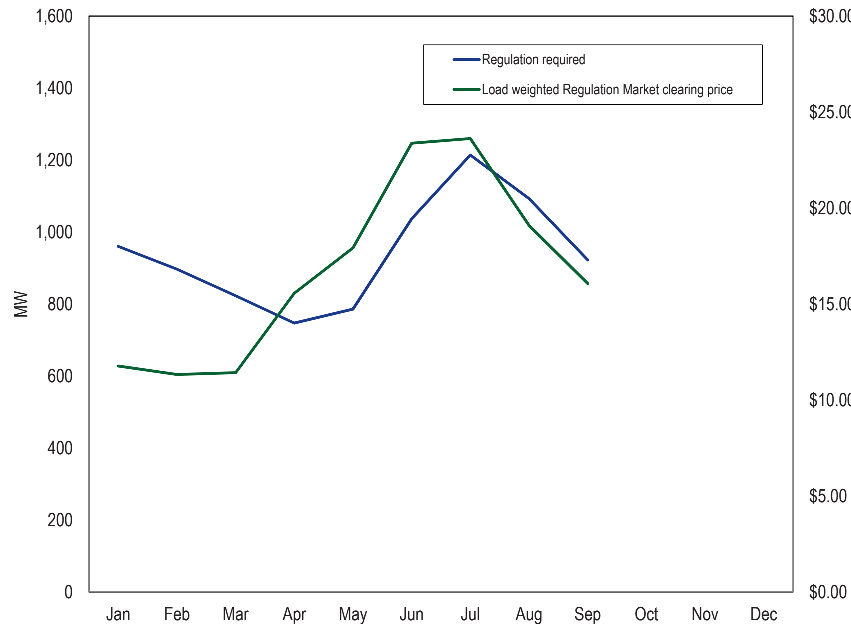


Figure 6-5 Monthly load weighted average regulation cost and price: January through September, 2011 (See 2010 SOM, Figure 6-5)

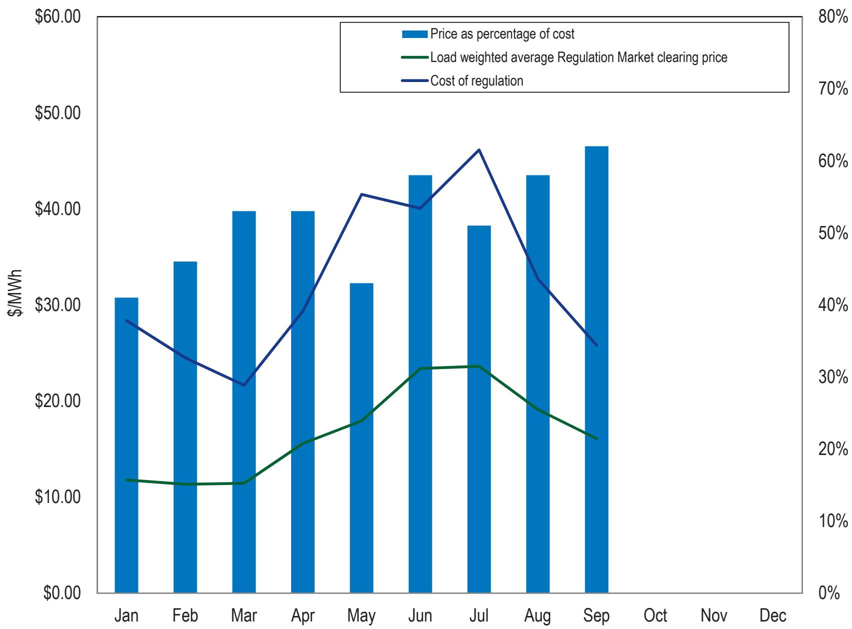


Table 6-11 Total regulation charges: January through September, 2011 (See 2010 SOM, Table 6-11)

Month	Scheduled Regulation (MW)	Total Regulation Charges	Weighted Regulation Market Clearing Price	Cost of Regulation
Jan	709,121	$20,116,704	$11.91	$28.37
Feb	594,515	$14,551,995	$11.49	$24.48
Mar	599,608	$12,967,924	$11.63	$21.63
Apr	523,565	$15,361,871	$16.06	$29.34
May	566,439	$23,500,438	$18.46	$41.49
Jun	691,666	$27,696,820	$23.38	$40.04
Jul	810,656	$37,375,988	$23.61	$46.11
Aug	803,781	$26,271,979	$19.10	$32.69
Sep	662,237	$17,074,805	$16.07	$25.78

Table 6-12 Comparison of load weighted price and cost for PJM Regulation, August 2005 through September 2011[25] (See 2010 SOM, Table 6-12)

Year	Load Weighted Regulation Market Price	Load Weighted Regulation Market Cost	Regulation Price as Percent Cost
2005	$64.03	$77.39	83%
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	$17.03	$32.71	52%

Analysis of Regulation Market Changes

Table 6-13 Summary of changes to Regulation Market design (See 2010 SOM, Table 6-13)

Prior Regulation Market Rules (Effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (Effective December 1, 2008)
1. No structural test for market power.	1. Three Pivotal Supplier structural test for market power.
2. Offers capped at cost for identified dominant suppliers. (American Electric Power Company(AEP) and Virginia Electric Power Company (Dominion)) Price offers capped at $100 per MW.	2. Offers capped at cost for owners that fail the TPS test. Price offers capped at $100 per MW.
3. Cost based offers include a margin of $7.50 per MW.	3. Cost based offers include a margin of $12.00 per MW.
4. Opportunity cost calculated based on the offer schedule on which the unit is dispatched in the energy market.	4. Opportunity cost calculated based on the lesser of the price-based offer schedule or the highest cost-based offer schedule in the energy market.
5. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	5. No regulation market revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.

25 The PJM Regulation Market in its current structure began August 1, 2005. See the *2005 State of the Market Report for PJM*, "Ancillary Service Markets." pp. 249-250.

Increase Offer Margin from $7.50 to $12.00

Table 6-14 Impact of $12 adder to cost based regulation offer: December 2008 through September 2011 (See 2010 SOM, Table 6-14)

Year	Month	Load Weighted Regulation Market Clearing Price	Load Weighted Regulation Market Clearing Price With Old Rule	Total Regulation Credits	Regulation Credits Attributable to New Rule	Percent Increase in Total Credits Due to Increase of Markup from $7.50 to $12.00
2008	Dec	$24.79	$23.47	$25,608,465	$890,749	3.5%
2009	Jan	$21.04	$19.91	$26,614,105	$813,654	3.1%
2009	Feb	$25.17	$23.95	$20,972,293	$734,061	3.5%
2009	Mar	$19.90	$19.37	$17,618,413	$316,889	1.8%
2009	Apr	$16.84	$16.36	$12,171,811	$258,778	2.1%
2009	May	$32.41	$31.93	$21,166,797	$265,494	1.3%
2009	Jun	$32.59	$32.19	$24,566,721	$312,979	1.3%
2009	Jul	$24.10	$23.25	$20,065,104	$414,408	2.1%
2009	Aug	$23.89	$23.37	$23,010,216	$369,407	1.6%
2009	Sep	$20.09	$19.32	$15,216,790	$497,484	3.3%
2009	Oct	$17.20	$16.31	$12,882,665	$445,635	3.5%
2009	Nov	$14.06	$13.48	$10,695,843	$269,283	2.5%
2009	Dec	$17.75	$16.72	$17,303,919	$600,585	3.5%
2010	Jan	$20.66	$20.49	$29,465,392	$125,523	0.4%
2010	Feb	$16.17	$16.13	$16,640,892	$29,265	0.2%
2010	Mar	$16.70	$16.57	$14,156,600	$76,654	0.5%
2010	Apr	$17.26	$17.15	$13,246,951	$57,940	0.4%
2010	May	$19.16	$18.85	$19,286,137	$168,308	0.9%
2010	Jun	$19.46	$19.28	$23,333,299	$107,986	0.5%
2010	Jul	$23.47	$23.38	$31,927,050	$60,049	0.2%
2010	Aug	$21.50	$21.46	$28,928,214	$28,048	0.1%
2010	Sep	$19.30	$19.20	$19,592,362	$59,153	0.3%

Table 6-14 continued next page

Year	Month	Load Weighted Regulation Market Clearing Price	Load Weighted Regulation Market Clearing Price With Old Rule	Total Regulation Credits	Regulation Credits Attributable to New Rule	Percent Increase in Total Credits Due to Increase of Markup from $7.50 to $12.00
2010	Oct	$13.57	$13.54	$10,613,185	$15,986	0.2%
2010	Nov	$11.69	$11.68	$11,930,514	$8,134	0.1%
2010	Dec	$14.04	$14.03	$25,225,775	$17,454	0.1%
2011	Jan	$11.77	$10.98	$20,116,696	$45,866	0.2%
2011	Feb	$11.33	$10.66	$14,551,986	$33,442	0.2%
2011	Mar	$11.42	$10.51	$12,967,915	$142,190	1.1%
2011	Apr	$15.56	$14.26	$15,361,860	$133,810	0.9%
2011	May	$17.92	$16.86	$23,500,428	$55,911	0.2%
2011	Jun	$23.38	$21.60	$27,696,810	$357,392	1.3%
2011	Jul	$23.61	$21.75	$37,375,975	$322,741	0.9%
2011	Aug	$19.10	$17.19	$26,271,969	$277,030	1.1%
2011	Sep	$16.07	$15.00	$17,074,790	$216,010	1.3%
Total				$687,157,940	$8,528,297	1.2%

Eliminate Offset Against Balancing Operating Reserves Credits

Table 6-15 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through September 2011 (See 2010 SOM, Table 6-15)

Year	Month	Balancing Operating Reserve Credits No Longer Offset	Total Regulation Credits	Percent of Regulation Credits No Longer Offsetting Operating Reserves
2008	Dec	$253,165	$25,608,465	1.0%
2009	Jan	$127,036	$26,614,105	0.5%
2009	Feb	$220,460	$20,972,293	1.1%
2009	Mar	$79,726	$17,618,413	0.5%
2009	Apr	$8,893	$12,171,811	0.1%
2009	May	$182,624	$21,166,797	0.9%
2009	Jun	$274,916	$24,566,721	1.1%
2009	Jul	$191,538	$20,065,104	1.0%
2009	Aug	$267,116	$23,010,216	1.2%
2009	Sep	$252,136	$15,216,790	1.7%
2009	Oct	$169,130	$12,882,665	1.3%
2009	Nov	$166,112	$10,695,843	1.6%
2009	Dec	$104,496	$17,303,919	0.6%
2010	Jan	$64,990	$29,465,392	0.2%
2010	Feb	$64,727	$16,640,892	0.4%
2010	Mar	$109,344	$14,156,600	0.8%
2010	Apr	$134,738	$13,246,951	1.0%
2010	May	$74,352	$19,286,137	0.4%
2010	Jun	$41,065	$23,333,299	0.2%
2010	Jul	$85,961	$31,927,050	0.3%
2010	Aug	$110,610	$28,928,214	0.4%
2010	Sep	$58,587	$19,592,362	0.3%
2010	Oct	$34,911	$10,613,185	0.3%
2010	Nov	$33,676	$11,930,514	0.3%
2010	Dec	$126,074	$25,225,775	0.5%
2011	Jan	$22,174	$20,116,704	0.1%
2011	Feb	$25,834	$14,551,995	0.2%
2011	Mar	$62,678	$12,967,924	0.5%
2011	Apr	$103,567	$15,361,871	0.7%
2011	May	$51,631	$23,500,428	0.2%
2011	Jun	$66,439	$27,696,810	0.2%
2011	Jul	$77,705	$37,375,975	0.2%
2011	Aug	$61,704	$26,271,969	0.2%
2011	Sep	$50,593	$17,074,790	0.3%
Total		$3,758,706	$687,157,978	0.5%

Table 6-15 continued next column.

Synchronized Reserve Market

Market Structure

Demand

Figure 6-6 Mid-Atlantic Subzone average hourly Required synchronized reserve and Tier 2 scheduled: January through September, 2011 (See 2010 SOM, Figure 6-7)

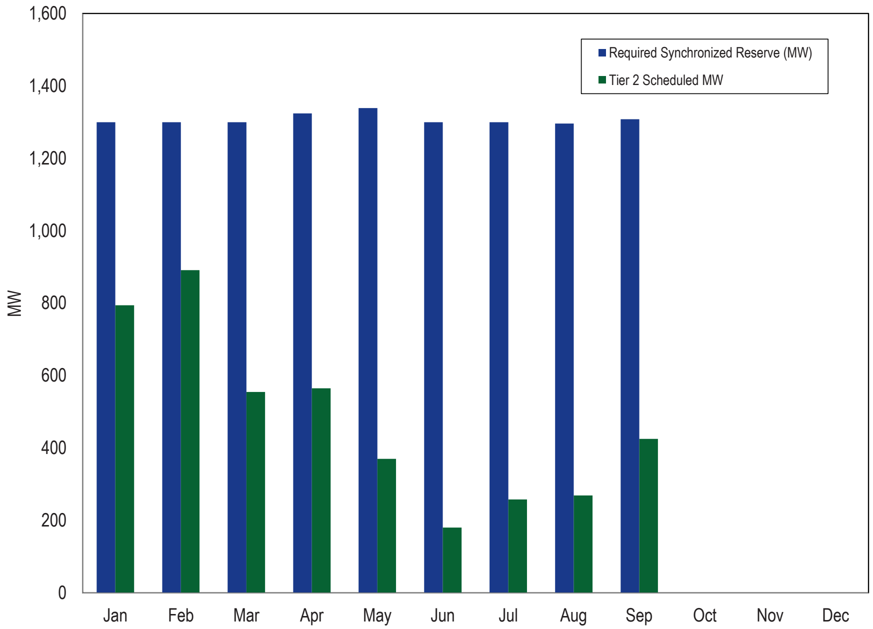


Figure 6-7 Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through September, 2011 (See 2010 SOM, Figure 6-8)

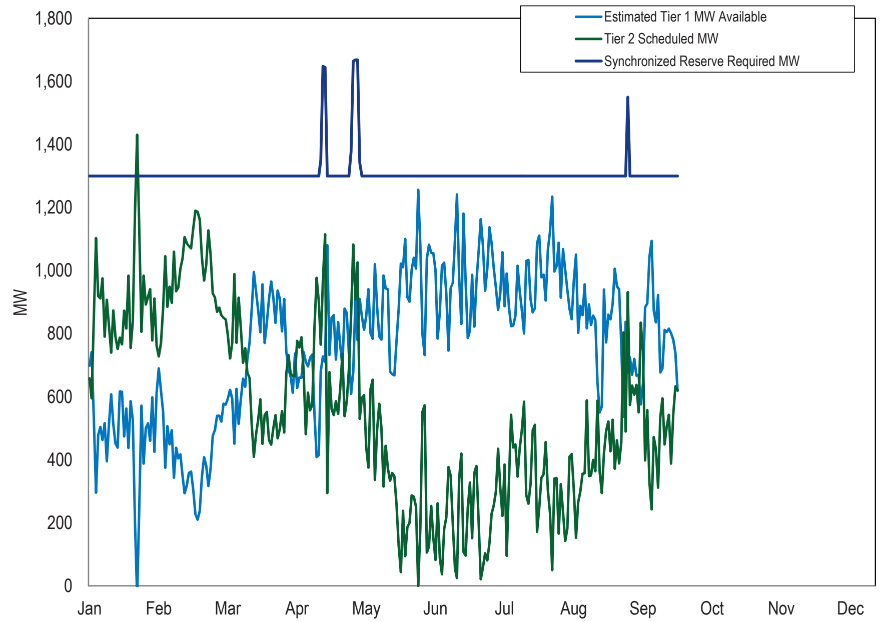


Table 6-16 ynchronized Reserve Market required MW, RFC zone and Mid-Atlantic subzone, December 2008 through September 2011 (New table)

Mid-Atlantic Subzone			RFC Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
Dec 2008	May 2010	1,150	Dec 2008	Jan 2009	1,305
May 2010	Jul 2010	1,200	Jan 2009	Mar 2010	1,320
Jul 2010	Sep 2011	1,300	Mar 2010	Sep 2011	1,350

Market Concentration

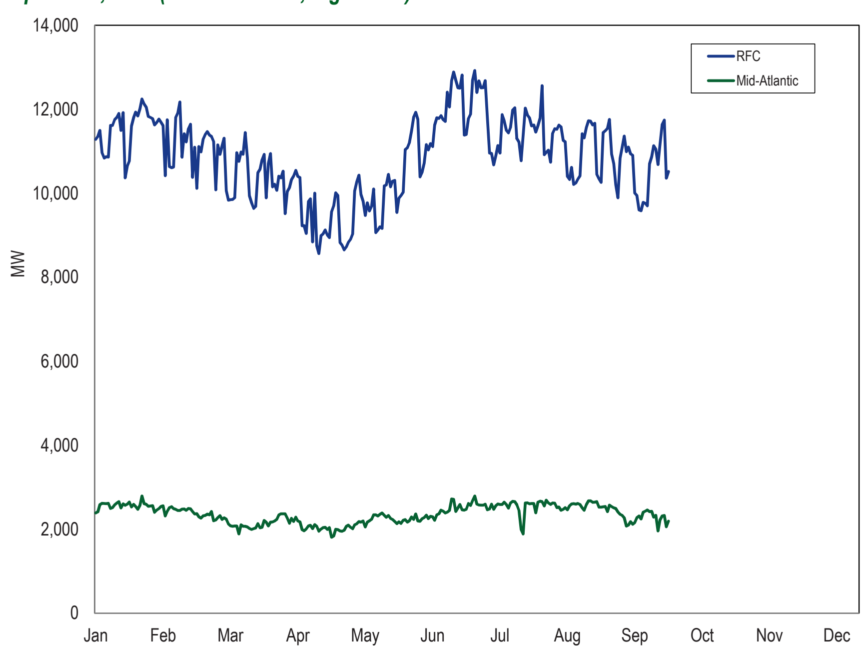
Table 6-17 Mid-Atlantic Subzone Tier 2 Synchronized Reserve Market cleared market shares[26]: January through September, 2011 (See 2010 SOM, Table 6-16)

Company Market Share Rank	Cleared Synchronized Reserve Average Market Share
1	33%
2	30%
3	21%
4	19%
5	16%
6	14%

Market Conduct

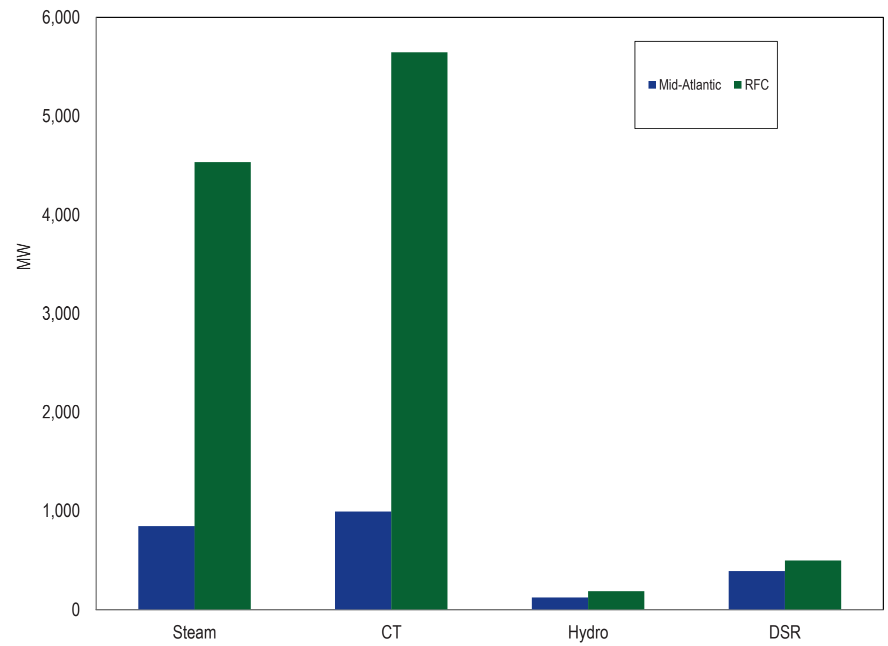
Offers

Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): January through September, 2011 (See 2010 SOM, Figure 6-9)



26 Note that the column "Cleared Synchronized Reserve Average Market Share" include the average market share for the provider only in hours when that provider had a market share greater than zero. For this reason it is possible for the market shares of all providers to sum to greater than one hundred percent.

Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through September, 2011 (See 2010 SOM, Table 6-10)

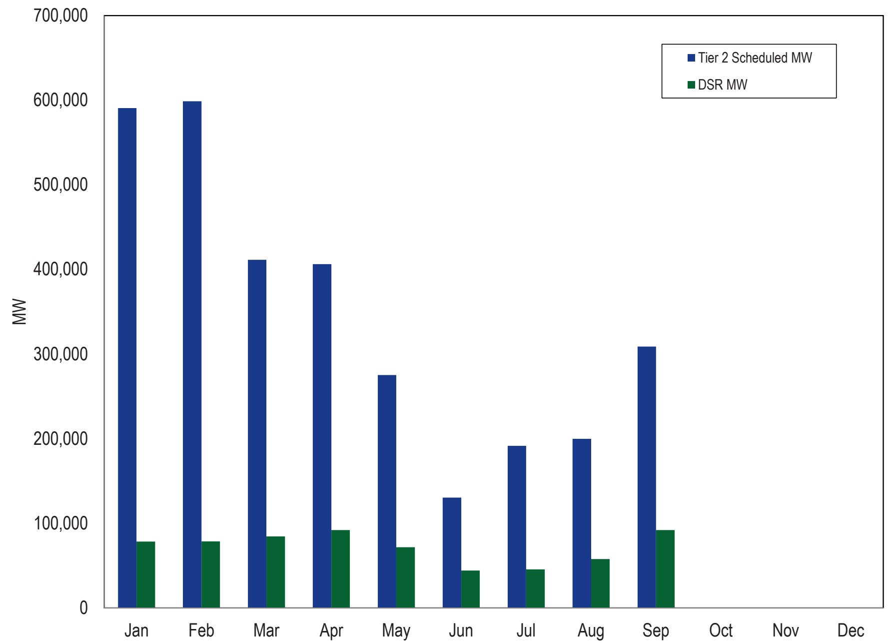


DSR

Table 6-18 Average 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 September 2010 and 2011 (See 2010 SOM, Table 6-17)

Year	Month	Average SRMCP	Average SRMCP when all cleared sychronized 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%
2011	Jan	$9.31	$0.10	0%
2011	Feb	$10.58	NA	0%
2011	Mar	$9.70	$2.04	2%
2011	Apr	$12.64	$1.84	10%
2011	May	$8.64	$1.71	14%
2011	Jun	$9.05	$1.18	10%
2011	Jul	$12.33	$0.62	6%
2011	Aug	$8.25	$0.78	7%
2011	Sep	$9.05	$1.73	15%

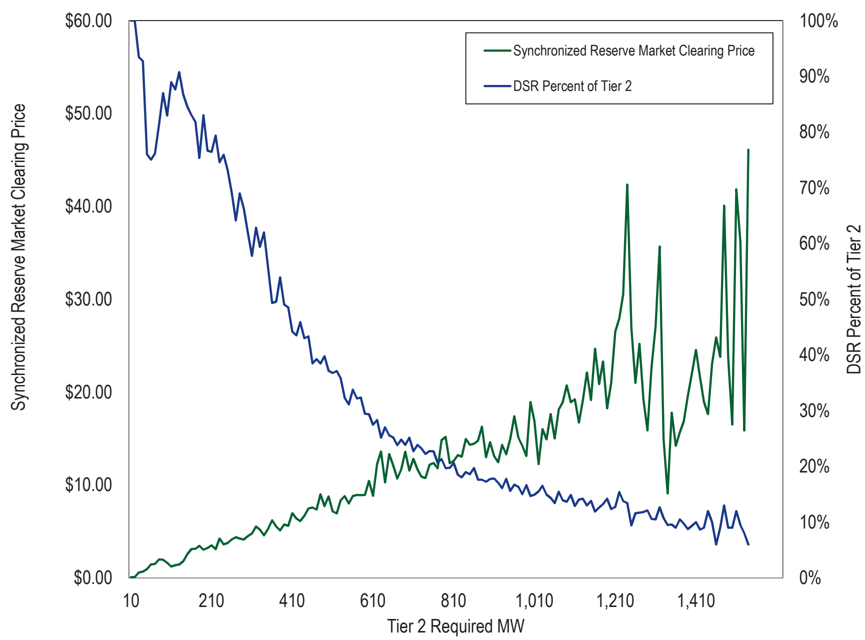
Figure 6-10 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through September, 2011 (See 2010 SOM, Figure 6-11)



Market Performance

Price

Figure 6-11 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: January through September, 2011 (See 2010 SOM, Figure 6-12)



Price and Cost

Figure 6-12 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through September, 2011 (See 2010 SOM, Figure 6-13)

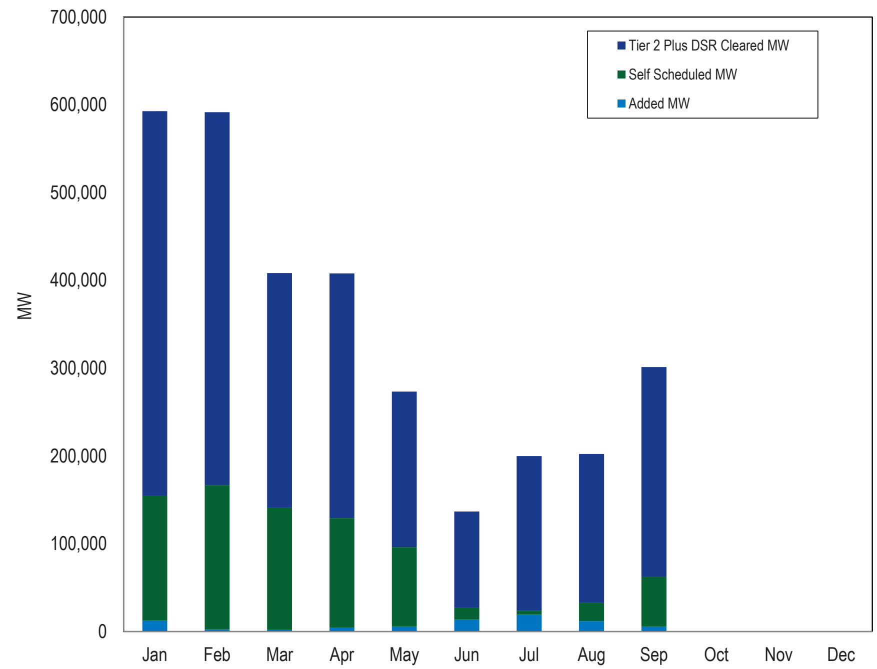


Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the Mid-Atlantic Subzone: January through September, 2011 (See 2010 SOM, Figure 6-14)

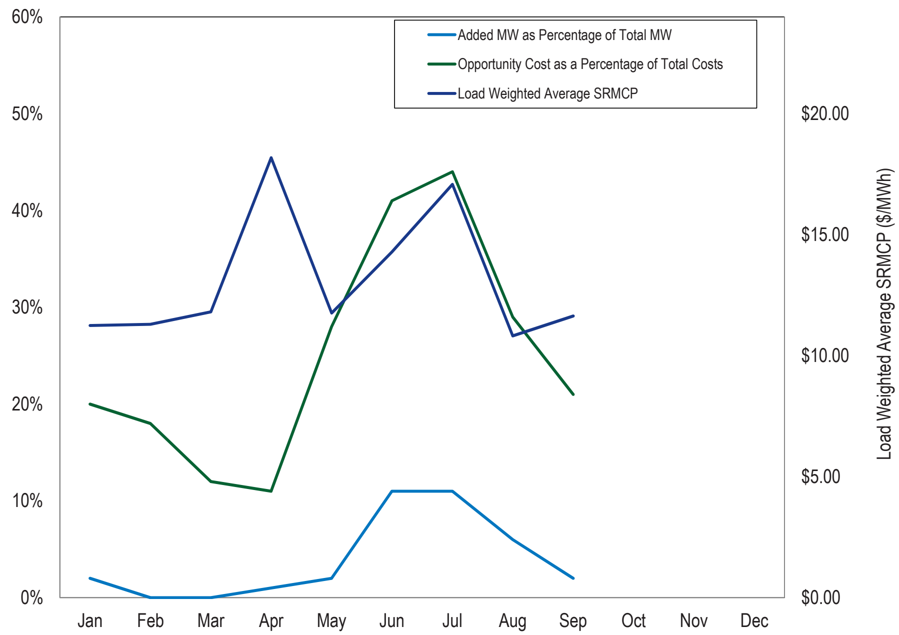


Table 6-19 Comparison of load weighted average price and cost for PJM Synchronized Reserve, January through September 2005 through 2011 (See 2010 SOM, Table 6-18)

Year	Load Weighted Average Synchronized Reserve Market Price	Load Weighted Average Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005 (Jan-Sep)	$12.81	$17.01	75%
2006 (Jan-Sep)	$14.40	$27.78	52%
2007 (Jan-Sep)	$18.24	$21.27	86%
2008 (Jan-Sep)	$10.87	$16.76	65%
2009 (Jan-Sep)	$6.38	$10.41	61%
2010 (Jan-Sep)	$11.51	$16.54	70%
2011 (Jan-Sep)	$12.00	$14.21	84%

Figure 6-14 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve load weighted average price and cost (Dollars per MW): January through September, 2011 (See 2010 SOM, Figure 6-15)

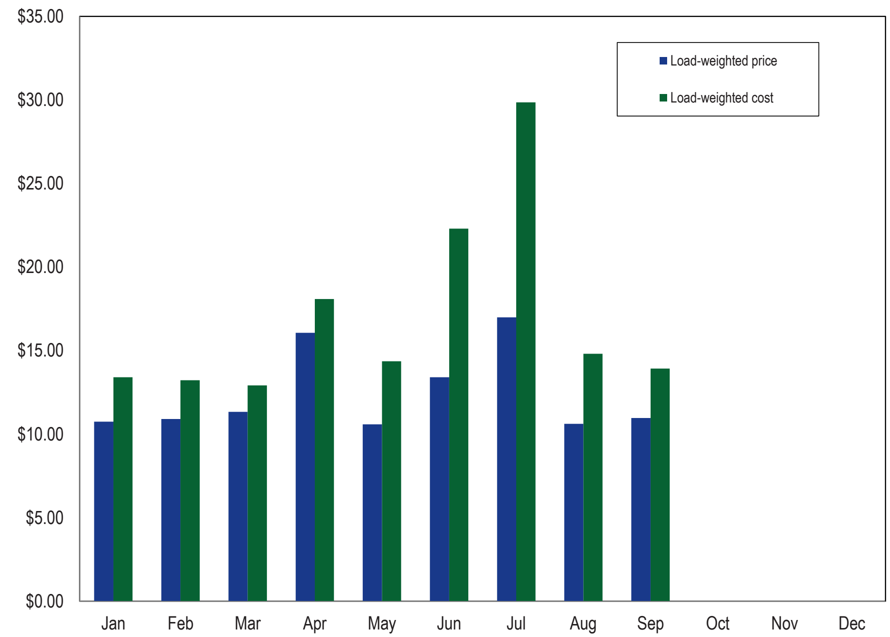


Table 6-20 Spinning Events, January 2009 through September 2011. (New table)

2009			2010			2011		
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-20-2009 17:33	RFC	10	MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5
JAN-21-2009 11:52	RFC	9	MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11
FEB-18-2009 18:38	Mid-Atlantic	10	APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16
FEB-19-2009 11:01	RFC	6	APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14
FEB-28-2009 06:19	RFC	5	MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14
MAR-03-2009 05:20	Mid-Atlantic	11	MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10
MAR-05-2009 01:30	Mid-Atlantic	43	MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12
MAR-07-2009 23:22	RFC	11	JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11
MAR-23-2009 23:40	Mid-Atlantic	10	JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6
MAR-23-2009 23:42	RFCNonMA	8	JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9
MAR-24-2009 13:20	Mid-Atlantic	8	JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6
MAR-25-2009 02:29	RFC	9	JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8
MAR-26-2009 13:08	RFC	10	JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21
MAR-26-2009 18:30	Mid-Atlantic	20	AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9
APR-24-2009 16:43	RFC	11	AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20
APR-26-2009 03:04	Mid-Atlantic	5	AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6
MAY-03-2009 15:07	RFC	10	AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7
MAY-17-2009 07:41	RFC	5	SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27
MAY-21-2009 21:37	RFC	13	SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7
JUN-18-2009 17:39	RFC	12	OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9
JUN-30-2009 00:17	Mid-Atlantic	8	OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8
JUL-26-2009 19:07	RFC	18	OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10
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			
OCT-26-2009 11:05	RFC	13	DEC-16-2010 18:40	Mid-Atlantic	20			
OCT-26-2009 19:55	RFC	8	DEC-17-2010 22:09	Mid-Atlantic	6			
NOV-20-2009 15:30	RFC	8	DEC-29-2010 19:01	Mid-Atlantic	15			
DEC-09-2009 22:34	Mid-Atlantic	34						
DEC-09-2009 22:37	RFCNonMA	31						
DEC-14-2009 11:11	Mid-Atlantic	8						

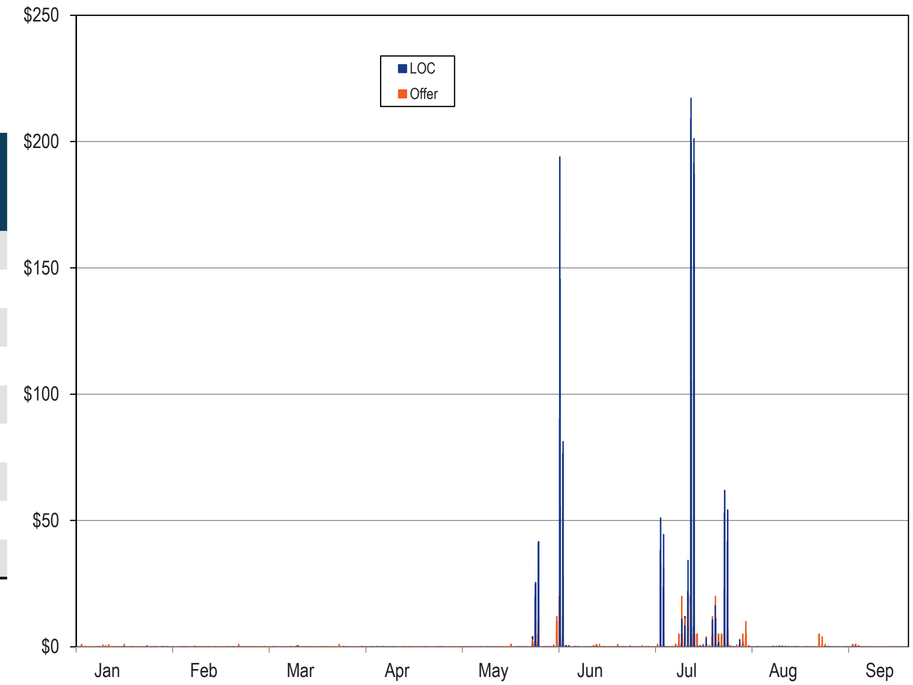
Day Ahead Scheduling Reserve (DASR)

Market Performance

Table 6-21 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September, 2011 (See 2010 SOM, Table 6-20)

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Purchased	Total DASR Credits
Jan	6,536	$0.00	$1.00	$0.03	4,862,520	$127,837
Feb	6,180	$0.00	$1.00	$0.02	4,152,665	$61,682
Mar	5,720	$0.00	$1.00	$0.01	4,249,733	$45,885
Apr	5,265	$0.00	$0.05	$0.01	3,790,932	$24,463
May	5,554	$0.00	$25.52	$0.29	4,132,056	$894,607
Jun	7,305	$0.00	$193.97	$2.26	5,259,795	$9,653,815
Jul	8,647	$0.00	$217.12	$4.21	6,433,574	$22,880,723
Aug	7,787	$0.00	$61.91	$0.75	5,793,554	$3,577,433
Sep	6,535	$0.00	$5.00	$0.07	4,704,950	$292,252

Figure 6-15 Hourly components of DASR clearing price: January through September 2011 (New Figure)



Black Start Service

Table 6-22 Black start yearly zonal charges for network transmission use: January through September, 2011 (See 2010 SOM, Table 6-21)

Blackstart Zone	Network Charges	Blackstart Rate ($/MW)
AECO	$347,152	$0.43
AEP	$447,904	$0.07
AP	$111,799	$0.05
ATSI	$34,687	$0.02
BGE	$1,376,538	$0.73
ComEd	$2,842,282	$0.48
DAY	$110,928	$0.12
DLCO	$26,354	$0.03
DPL	$312,969	$0.28
JCPL	$370,744	$0.21
Met-Ed	$359,639	$0.45
PECO	$746,996	$0.31
PENELEC	$263,270	$0.33
Pepco	$265,595	$0.15
PPL	$108,783	$0.05
PSEG	$2,193,049	$0.75
UGI	$108,783	$0.05

SECTION 7 – CONGESTION

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.[1] 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. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying characteristics of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would require direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[2]

The Market Monitoring Unit (MMU) analyzed congestion and its influence on PJM markets in the first nine months of 2011.

Highlights

- Congestion costs in the first nine months of 2011 decreased by 25.7 percent over congestion costs in the first nine months of 2010 (Table 7-2).

- Net balancing congestion costs were -$192.9 million in the first nine months of 2011 and -$169.8 million in the first nine months of 2010. Negative balancing congestion costs indicate that the congestion payments in the Day-Ahead Market exceeded congestion payments in the Real-Time Market.

- Measured in terms of the total congestion bill, calculated by subtracting generation congestion credits from load congestion payments plus explicit congestion costs by zone, ComEd was the most congested zone in the first nine months of 2011, despite having, on average, negative congestion components in zonal LMPs. Measured in these terms, ComEd accounted for 22.2 percent of the total congestion cost (Table 7-21). In the first nine months of 2010, AP was the most congested zone, accounting for 19.8 percent of the total net congestion cost (Table 7-22.)[3]

- Monthly congestion costs in the first nine months of 2011 were lower than monthly congestion costs in the same period in 2010, with the exception of January and March (Table 7-3).

- PJM backbone transmission projects are a subset of significant baseline transmission upgrades. The backbone upgrades are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets.

  On August 18, 2011, the PJM Board of Managers instructed Pepco Holdings, Inc. (PHI) that the MAPP in-service date of 2015 was moved to 2019-2021, and advised PHI to sustain efforts needed to allow the MAPP project to be resumed.

  In October 2011, the Rapid Response Team for Transmission, a federal interagency team led by the White House Council on Environmental Quality, included the Susquehanna-Roseland power line project in its list of seven transmission line projects for rapid review and permit process.

1 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.

2 See the *2010 State of the Market Report for PJM*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

3 Since the *2008 State of the Market Report* the MMU has provided load congestion payments and generation congestion credits calculated as constraint specific net congestion costs by organization by zone. Load congestion payments and generation congestion credits are calculated by constraint for each zone. Within each zone, where constraint specific congestion payments and credits are of the same sign, the payments and credits are netted by organization within the zone. For a specific constraint, this results in an organization being assigned either net generation congestion credits or net load congestion charges within a zone. All net generation credits and net congestion payments are summed across organizations within each zone to determine the total congestion generation credits, total congestion load charges and total net congestion charges by zone. These results are used to calculate system-wide total congestion generation credits and total congestion load charges.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

Overview

Congestion Cost

- Total congestion costs equal net congestion costs plus explicit 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. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs. Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the Real-Time Energy Market.

- 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.[4] If an area is downstream from the constrained element, the area will experience positive congestion costs. If an area is upstream from the constrained element, the area will experience negative congestion costs.

- 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.

- **Total Congestion.** Total congestion costs decreased by $292.1 million or 25.7 percent, from $1,138.5 million in the first nine months of 2010 to $846.4 million in the first nine months of 2011. Day-ahead congestion costs decreased by $269.1 million or 20.6 percent, from $1,308.3 million in the first nine months of 2010 to $1,039.2 million in the first nine months of 2011. Balancing congestion costs decreased by $23.1 million or 13.6 percent from -$169.8 million in the first nine months of 2010 to -$192.9 million in the first nine months of 2011. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this section treat ATSI as part of MISO for the period from January through May and as part of PJM for the period from June through September.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In the first nine months of 2011, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in the first nine months of 2011 ranged from $35.5 million in May to $241.8 million in January.

Congestion Component of LMP and Facility or Zonal Congestion

- **Congestion Component of Locational Marginal Price (LMP).** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the 5004/5005 interface, the Belmont transformer, West Interface, and the AEP-Dominion interface. (Table 7-13)

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time

4 The SMP is the price of the distributed load reference bus. The price at the reference bus is equivalent to the five minute real-time or hourly day-ahead load weighted PJM LMP.

Market in 2011.[5] Day-ahead congestion frequency increased by 35.7 percent from 75,783 congestion event hours in the first nine months of 2010 to 102,830 congestion event hours in the first nine months of 2011. Day-ahead, congestion-event hours decreased on internal PJM interfaces while congestion-event hours increased on transmission lines, transformers and reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (MISO).

Real-time congestion frequency decreased by 3.6 percent from 17,240 congestion event hours in the first nine months of 2010 to 16,613 congestion event hours in the first nine months of 2011. Real-time, congestion-event hours decreased on the internal PJM interfaces and transmission lines, while congestion-event hours increased on transformers and reciprocally coordinated flowgates between PJM and MISO.

Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. During the first nine months of 2011, for only 6.1 percent of Day Ahead Market facility constrained hours were the same facilities also constrained in the Real Time Market. During the first nine months of 2011, for 37.3 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 the first nine months of 2011. With $215.7 million in total congestion costs, it accounted for 25.5 percent of the total PJM congestion costs in the first nine months of 2011. The top five constraints in terms of congestion costs together contributed $423.5 million, or 50.0 percent, of the total PJM congestion costs in the first nine months of 2011. The top five constraints were the AP South interface, the 5004/5005 interface, the Belmont transformer, West interface and the AEP – Dominion interface.

- **Zonal Congestion.** Measured in terms of the total congestion bill, calculated by subtracting generation congestion credits from load congestion payments plus explicit congestion costs by zone, ComEd was the most congested zone in the first nine months of 2011. ComEd had –$296.8 million in total load charges, -$506.4 million in total generation credits and -$21.8 million in explicit congestion, providing $187.8 million in total net congestion charges, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The Crete – St. Johns flowgate (a reciprocally coordinated flowgate between PJM and MISO) and Electric Junction – Nelson transmission line, AP South interface, East Frankfort – Crete transmission line and the Pleasant Valley – Belvidere transmission line contributed $88.7 million, or 47.2 percent of the total ComEd Control Zone congestion costs.

  Similarly, the AEP Control Zone recorded the second highest congestion cost in PJM in the first nine months of 2011, with $163.3 million. The AP South interface contributed $31.5 million, or 19.3 percent of the total AEP Control Zone congestion cost in the first nine months of 2011. The AP Control Zone recorded the third highest congestion cost in PJM in the first nine months of 2011, with a cost of $130.1 million. The AP South interface contributed $59.0 million, or 45.4 percent of the total AP Control Zone congestion cost in the first nine months of 2011. The control zones in the Western and Southern regions accounted for $589.84 million, or 69.7 percent of congestion cost and the control zones in the Eastern region accounted for $256.56 million or 30.3 percent of congestion cost.

- **Regional and Zonal Congestion.** Tables reporting regional and zonal congestion have been moved from this section of the report to Appendix A.[6]

- **Ownership.** In the PJM market, both physical and financial participants make virtual supply offers (increments) and virtual demand bids (decrements). A participant is classified as a physical entity if the entity primarily takes physical positions in PJM markets. Physical entities include utilities and wholesale customers. Financial entities include banks, hedge funds, retail service providers and speculators, who primarily take financial positions in PJM markets. All affiliates are considered a single entity for this categorization. For example, under this classification, the trading affiliate of a utility would be treated as a physical company. In the first nine months of 2011, financial companies as a group were net recipients of congestion credits, whereas physical companies were net payers of congestion charges. In the first nine months of 2011, financial companies received net $79.5 million, a decrease of $22.1 million or 21.8 percent compared to the first nine months of 2010. In the first nine months of 2011, physical companies

5 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.

6 See the *Quarterly State of the Market Report for PJM: January through September*, Appendix A.

paid net $925.9 million in congestion charges, a decrease of $314.1 million or 25.3 percent compared to the first nine months of 2010.

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 typically 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; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); and Susquehanna – Roseland.

On August 18, 2011, the PJM Board of Managers instructed Pepco Holdings, Inc. (PHI) to delay the construction of the MAPP transmission line. The PJM RTEP analysis, using the most current economic forecasts, demand response commitments and potential new generation, showed that the MAPP project can be delayed. As a result, the initial MAPP in-service date of 2015 has been moved to 2019-2021. The PJM Board of Managers advised PHI to sustain efforts needed to allow the MAPP project to be resumed when it is needed.[7]

In early October 2011, the Interagency Rapid Response Team for Transmission named the Susquehanna-Roseland power line project to the initial list of seven transmission line projects for rapid review and permit process. The Rapid Response Team is a federal interagency team consisting of the following agencies: the Department of Agriculture, the Department of Commerce, the Department of Defense, the Department of Energy, the Department of the Interior, the Environmental Protection Agency, the Federal Electric Regulatory Commission, the Advisory Council on Historic Preservation and the White House Council on Environmental Quality.[8] The Rapid Response Team for Transmission was implemented to coordinate, improve and accelerate the permitting process for critical transmission line projects in other to improve overall reliability of the US power grid.[9]

7 See "PJM Board directs delay in MAPP Transmission Line" (Accessed October 22, 2011) <http://www.pjm.com/about-pjm/newsroom/newsletter-notices/state-lines/2011/september.aspx#Article_4>.

8 See "Interagency Rapid Response Team for Transmission" (Accessed October 28, 2011) <http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission>.

9 See "PJM Issues Statement on Rapid Response Team Selection of Susquehanna-Roseland Project" (Accessed October 24, 2011) <http://www.pjm.com/~/media/about-pjm/newsroom/2011-releases/20111005-pjm-issues-statement-on-rapid-response-team-selection-of-susquehanna-roseland-project.ashx>.

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical distribution of load. Total congestion costs decreased by $292.1 million or 25.7 percent, from $1,138.5 million in the first nine months of 2010 to $846.4 million in the first nine months of 2011. Day-ahead congestion costs decreased by $269.1 million or 20.6 percent, from $1,308.3 million in the first nine months of 2010 to $1,039.2 million in the first nine months of 2011. Balancing congestion costs decreased by $23.1 million or 13.6 percent, from -$169.8 million in the first nine months of 2010 to -$192.9 million in the first nine months of 2011. 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. Day-ahead congestion frequency increased 35.7 percent from 75,783 congestion event hours in the first nine months of 2010 to 102,830 congestion event hours in the first nine months of 2011. Real-time congestion frequency decreased 3.6 percent from 17,240 congestion event hours in the first nine months of 2010 to 16,613 congestion event hours in the first nine months of 2011.

ARRs and FTRs served as an effective, but not complete, hedge against congestion. ARR and FTR revenues hedged 96.9 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market for the 2010 to 2011 planning period. For the first four months (June through September) of the 2011 to 2012 planning period, total ARR and FTR revenues hedged more than 100 percent of the congestion costs within PJM.[10] FTRs were paid at 84.9 percent of the target allocation level for the full 2010 to 2011 planning period, and at 90.9 percent of the target allocation level for the first four months (June through September) of the 2011 to 2012 planning period.[11]

The AP South Interface was the largest contributor to congestion costs in the first nine months of 2011, accounting for 25.5 percent of total congestion costs in the first nine months of 2010. The top five constraints accounted for 50.0 percent of total congestion costs.

10 See the *2011 Quarterly State of the Market Report for PJM: January through September,* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-18, "ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011."

11 See the *2011 Quarterly State of the Market Report for PJM: January through September,* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-16, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012 through September 30, 2011".

Congestion

Total Calendar Year Congestion

Table 7-1 Total PJM congestion (Dollars (Millions)): January through September for calendar years 2006 to 2011 (See 2010 SOM, Table 7-1)

	Congestion Charges	Percent Change
2006 (Jan - Sep)	$1,424	NA
2007 (Jan - Sep)	$1,382	(3%)
2008 (Jan - Sep)	$1,843	33%
2009 (Jan - Sep)	$544	(71%)
2010 (Jan - Sep)	$1,139	109%
2011 (Jan - Sep)	$846	(26%)

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through September, 2010 and 2011 (See 2010 SOM, Table 7-2)

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2010 (Jan - Sep)	$301.2	($886.2)	($48.9)	$1,138.5
2011 (Jan - Sep)	$421.1	($530.0)	($104.7)	$846.4

Monthly Congestion

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): January through September, 2010 and 2011 (See 2010 SOM, Table 7-3)

	2010	2011	Change	Percent Change
Jan	$218.3	$241.8	$23.5	10.8%
Feb	$106.4	$74.0	($32.4)	(30.4%)
Mar	$20.4	$44.1	$23.7	116.4%
Apr	$42.5	$39.0	($3.6)	(8.4%)
May	$68.5	$35.5	($33.0)	(48.2%)
Jun	$188.5	$125.0	($63.5)	(33.7%)
Jul	$268.9	$161.1	($107.8)	(40.1%)
Aug	$105.1	$59.5	($45.6)	(43.4%)
Sep	$119.9	$66.5	($53.4)	(44.6%)
Total	$1,138.5	$846.4	($292.1)	(25.7%)

Congestion Component of LMP

Table 7-4 Annual average congestion component of LMP: January through September 2010 and 2011 (See 2010 SOM, Table 7-4)

	2010 (Jan - Sep)		2011 (Jan - Sep)	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$3.16	$3.87	$3.74	$3.69
AEP	($4.63)	($5.23)	($2.79)	($3.41)
AP	($0.28)	($0.42)	$0.06	($0.02)
ATSI	$0.00	$0.00	($2.53)	($3.21)
BGE	$6.15	$6.72	$4.29	$5.01
ComEd	($6.65)	($7.87)	($6.28)	($7.23)
DAY	($5.17)	($5.92)	($3.62)	($3.92)
DLCO	($4.71)	($6.08)	($3.55)	($3.61)
DPL	$3.24	$3.99	$3.32	$2.97
Dominion	$5.93	$5.31	$3.30	$3.45
JCPL	$2.55	$2.79	$3.06	$3.44
Met-Ed	$4.03	$3.78	$2.77	$2.78
PECO	$2.90	$2.99	$3.42	$3.04
PENELEC	($1.34)	($2.36)	($0.41)	($0.41)
Pepco	$7.39	$6.61	$5.01	$3.79
PPL	$2.29	$2.38	$3.04	$3.15
PSEG	$3.04	$3.59	$3.76	$4.07
RECO	$2.16	$2.04	$1.20	($0.70)

Congested Facilities

Congestion by Facility Type and Voltage

Table 7-5 Congestion summary (By facility type): January through September 2011 (See 2010 SOM, Table 7-5)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($1.0)	($67.6)	$9.6	$76.2	$6.3	$9.2	($59.5)	($62.4)	$13.8	15,136	4,251
Interface	$137.7	($275.5)	($13.3)	$399.9	$28.6	$30.3	$11.4	$9.7	$409.6	7,091	1,607
Line	$123.6	($194.8)	$25.9	$344.4	$14.9	$39.8	($60.1)	($85.0)	$259.4	59,093	7,332
Other	$1.9	($1.5)	$0.6	$4.0	$1.4	$4.0	($0.2)	($2.8)	$1.2	622	145
Transformer	$106.0	($83.0)	$18.0	$207.1	($0.6)	$10.1	($37.3)	($48.0)	$159.0	20,874	3,278
Unclassified	$1.6	($1.1)	$5.0	$7.7	$0.8	$0.2	($4.9)	($4.3)	$3.4	NA	NA
Total	$369.8	($623.6)	$45.8	$1,039.2	$51.3	$93.6	($150.5)	($192.9)	$846.4	102,816	16,613

Table 7-6 Congestion summary (By facility type): January through September 2010 (See 2011 SOM, Table 7-6)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($0.1)	($32.0)	$5.1	$37.0	($2.8)	$3.0	($21.8)	($27.7)	$9.4	4,168	1,668
Interface	$68.6	($504.1)	$4.6	$577.2	$18.8	$13.4	($3.6)	$1.8	$579.1	7,612	2,020
Line	$145.9	($318.2)	$48.9	$513.0	($23.1)	$20.0	($78.8)	($121.9)	$391.1	53,605	11,109
Other	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Transformer	$92.5	($70.2)	$6.2	$168.9	($3.0)	$5.0	($14.2)	($22.1)	$146.7	10,398	2,443
Unclassified	$4.3	($3.1)	$4.7	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	NA	NA
Total	$311.2	($927.5)	$69.5	$1,308.3	($10.1)	$41.3	($118.4)	($169.8)	$1,138.5	75,783	17,240

Table 7-7 Congestion Event Hours (Day Ahead against Real Time): January through September 2010 and 2011 (See 2010 SOM, Table 7-7)

	Congestion Event Hours					
	2011 (Jan - Sep)			2010 (Jan - Sep)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	15,136	1,632	10.8%	4,168	440	10.6%
Interface	7,091	1,021	14.4%	7,612	1,333	17.5%
Line	59,093	2,125	3.6%	53,605	3,938	7.3%
Other	622	2	0.3%	0	0	0.0%
Transformer	20,874	1,475	7.1%	10,398	957	9.2%
Total	102,816	6,255	6.1%	75,783	6,668	8.8%

Table 7-8 Congestion Event Hours (Real Time against Day Ahead): January through September 2010 and 2011 (See 2010 SOM, Table 7-8)

	Congestion Event Hours					
	2011 (Jan - Sep)			2010 (Jan - Sep)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	4,251	1,638	38.5%	1,668	458	27.5%
Interface	1,607	1,020	63.5%	2,020	1,333	66.0%
Line	7,332	2,090	28.5%	11,109	3,837	34.5%
Other	145	2	1.4%	0	0	0.0%
Transformer	3,278	1,445	44.1%	2,443	875	35.8%
Total	16,613	6,195	37.3%	17,240	6,503	37.7%

Table 7-9 Congestion summary (By facility voltage): January through September 2011 (See 2010 SOM, Table 7-9)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$2.1	($6.9)	$2.0	$11.0	$2.0	$1.3	($2.4)	($1.7)	$9.3	854	139
500	$209.5	($300.2)	($8.6)	$501.2	$29.2	$34.8	($6.8)	($12.4)	$488.7	14,917	3,332
345	$13.9	($105.8)	$11.2	$130.8	$5.5	$18.1	($60.6)	($73.2)	$57.7	17,301	3,080
230	$53.6	($96.5)	$11.6	$161.7	$13.5	$15.8	($30.6)	($32.9)	$128.8	17,287	2,633
161	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.3)	($0.4)	($0.4)	0	29
138	$66.3	($98.0)	$21.7	$186.0	$2.0	$16.0	($43.8)	($57.8)	$128.2	37,991	6,126
115	$9.2	($14.1)	$3.0	$26.4	$0.2	$5.3	($1.1)	($6.2)	$20.2	7,826	739
69	$13.6	($0.9)	($0.2)	$14.4	($1.9)	$2.1	$0.1	($4.0)	$10.4	6,614	530
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	17	0
Unclassified	$1.6	($1.1)	$5.0	$7.7	$0.8	$0.2	($4.9)	($4.3)	$3.4	NA	NA
Total	$369.8	($623.6)	$45.8	$1,039.2	$51.3	$93.6	($150.5)	($192.9)	$846.4	102,816	16,613

Table 7-10 Congestion summary (By facility voltage): January through September 2010 (See 2010 SOM, Table 7-10)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$1.2	($4.5)	$1.0	$6.8	($1.1)	$0.7	($5.1)	($6.9)	($0.2)	431	250
500	$139.6	($585.3)	$13.0	$737.9	$14.6	$6.5	($25.5)	($17.5)	$720.5	13,066	4,653
345	($5.9)	($110.8)	$19.4	$124.4	($7.2)	$8.8	($54.5)	($70.5)	$53.8	8,735	2,461
230	$41.9	($120.4)	$18.4	$180.7	$0.7	$16.4	($17.9)	($33.6)	$147.1	14,893	2,822
138	$84.3	($100.6)	$12.2	$197.1	($11.6)	$4.7	($14.0)	($30.4)	$166.7	27,292	5,307
115	$30.5	($6.0)	$0.5	$37.1	$0.1	$3.5	($1.0)	($4.4)	$32.6	5,080	1,185
69	$14.9	$3.1	$0.3	$12.1	($5.6)	$0.7	($0.4)	($6.6)	$5.5	5,904	543
35	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
34	($0.0)	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	37	19
14	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	21	0
13	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
12	$0.3	$0.2	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	323	0
Unclassified	$4.3	($3.1)	$4.7	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	NA	NA
Total	$311.2	($927.5)	$69.5	$1,308.3	($10.1)	$41.3	($118.4)	($169.8)	$1,138.5	75,783	17,240

Constraint Duration

Table 7-11 Top 25 constraints with frequent occurrence: January through September 2010 to 2011 (See 2010 SOM, Table 7-11)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2010	2011	Change	2010	2011	Change	2010	2011	Change	2010	2011	Change
1	South Mahwah - Waldwick	Line	0	4,651	4,651	8	473	465	0%	53%	53%	0%	5%	5%
2	Belmont	Transformer	1,057	3,862	2,805	109	497	388	12%	44%	32%	1%	6%	4%
3	AP South	Interface	3,512	3,341	(171)	1,251	870	(381)	40%	38%	(2%)	14%	10%	(4%)
4	Crete - St Johns Tap	Flowgate	800	2,763	1,963	245	640	395	9%	32%	22%	3%	7%	5%
5	Danville - East Danville	Line	148	3,305	3,157	0	0	0	2%	38%	36%	0%	0%	0%
6	Michigan City - Laporte	Flowgate	0	2,323	2,323	36	571	535	0%	27%	27%	0%	7%	6%
7	Cox's Corner - Marlton	Line	13	2,620	2,607	0	0	0	0%	30%	30%	0%	0%	0%
8	Electric Jct - Nelson	Line	1,454	2,314	860	236	158	(78)	17%	26%	10%	3%	2%	(1%)
9	Wolfcreek	Transformer	209	2,148	1,939	0	226	226	2%	25%	22%	0%	3%	3%
10	Fairview	Transformer	46	2,262	2,216	0	0	0	1%	26%	25%	0%	0%	0%
11	Wylie Ridge	Transformer	504	1,882	1,378	368	357	(11)	6%	21%	16%	4%	4%	(0%)
12	Brues - West Bellaire	Line	0	1,537	1,537	78	485	407	0%	18%	18%	1%	6%	5%
13	Pinehill - Stratford	Line	1,138	1,898	760	0	0	0	13%	22%	9%	0%	0%	0%
14	Linden - VFT	Line	95	1,828	1,733	0	0	0	1%	21%	20%	0%	0%	0%
15	Bunsonville - Eugene	Flowgate	31	1,802	1,771	0	0	0	0%	21%	20%	0%	0%	0%
16	East Frankfort - Crete	Line	2,242	1,425	(817)	801	315	(486)	26%	16%	(9%)	9%	4%	(6%)
17	Oak Grove - Galesburg	Flowgate	61	1,098	1,037	116	622	506	1%	13%	12%	1%	7%	6%
18	Clover	Transformer	464	1,193	729	243	460	217	5%	14%	8%	3%	5%	2%
19	Emilie - Falls	Line	8	1,625	1,617	24	11	(13)	0%	19%	18%	0%	0%	(0%)
20	AEP-DOM	Interface	471	1,285	814	89	172	83	5%	15%	9%	1%	2%	1%
21	Waukegan - Zion	Line	13	1,377	1,364	0	4	4	0%	16%	16%	0%	0%	0%
22	Pleasant Valley - Belvidere	Line	1,775	991	(784)	355	315	(40)	20%	11%	(9%)	4%	4%	(0%)
23	Redoak - Sayreville	Line	795	1,276	481	57	11	(46)	9%	15%	5%	1%	0%	(1%)
24	Conesville Prep - Conesville	Line	171	1,271	1,100	0	0	0	2%	15%	13%	0%	0%	0%
25	Athenia - Saddlebrook	Line	2,947	1,148	(1,799)	331	4	(327)	34%	13%	(21%)	4%	0%	(4%)

Table 7-12 Top 25 constraints with largest year-to-year change in occurrence: January through September 2010 to 2011 (See 2010 SOM, Table 7-12)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2010	2011	Change	2010	2011	Change	2010	2011	Change	2010	2011	Change
1	South Mahwah - Waldwick	Line	0	4,651	4,651	8	473	465	0%	53%	53%	0%	5%	5%
2	Belmont	Transformer	1,057	3,862	2,805	109	497	388	12%	44%	32%	1%	6%	4%
3	Danville - East Danville	Line	148	3,305	3,157	0	0	0	2%	38%	36%	0%	0%	0%
4	Michigan City - Laporte	Flowgate	0	2,323	2,323	36	571	535	0%	27%	27%	0%	7%	6%
5	Waterman - West Dekalb	Line	2,543	0	(2,543)	288	0	(288)	29%	0%	(29%)	3%	0%	(3%)
6	Cox's Corner - Marlton	Line	13	2,620	2,607	0	0	0	0%	30%	30%	0%	0%	0%
7	Crete - St Johns Tap	Flowgate	800	2,763	1,963	245	640	395	9%	32%	22%	3%	7%	5%
8	Fairview	Transformer	46	2,262	2,216	0	0	0	1%	26%	25%	0%	0%	0%
9	Wolfcreek	Transformer	209	2,148	1,939	0	226	226	2%	25%	22%	0%	3%	3%
10	Athenia - Saddlebrook	Line	2,947	1,148	(1,799)	331	4	(327)	34%	13%	(21%)	4%	0%	(4%)
11	Tiltonsville - Windsor	Line	2,391	736	(1,655)	410	70	(340)	27%	8%	(19%)	5%	1%	(4%)
12	Brues - West Bellaire	Line	0	1,537	1,537	78	485	407	0%	18%	18%	1%	6%	5%
13	Bunsonville - Eugene	Flowgate	31	1,802	1,771	0	0	0	0%	21%	20%	0%	0%	0%
14	Linden - VFT	Line	95	1,828	1,733	0	0	0	1%	21%	20%	0%	0%	0%
15	Emilie - Falls	Line	8	1,625	1,617	24	11	(13)	0%	19%	18%	0%	0%	(0%)
16	Doubs	Transformer	1,230	51	(1,179)	423	51	(372)	14%	1%	(13%)	5%	1%	(4%)
17	Oak Grove - Galesburg	Flowgate	61	1,098	1,037	116	622	506	1%	13%	12%	1%	7%	6%
18	Waukegan - Zion	Line	13	1,377	1,364	0	4	4	0%	16%	16%	0%	0%	0%
19	Wylie Ridge	Transformer	504	1,882	1,378	368	357	(11)	6%	21%	16%	4%	4%	(0%)
20	East Frankfort - Crete	Line	2,242	1,425	(817)	801	315	(486)	26%	16%	(9%)	9%	4%	(6%)
21	Bedington - Black Oak	Interface	1,819	624	(1,195)	47	7	(40)	21%	7%	(14%)	1%	0%	(0%)
22	Danville - East Danville	Line	1,307	0	(1,307)	138	321	183	15%	0%	(15%)	2%	4%	2%
23	Branchburg - Readington	Line	1,210	246	(964)	184	40	(144)	14%	3%	(11%)	2%	0%	(2%)
24	Conesville Prep - Conesville	Line	171	1,271	1,100	0	0	0	2%	15%	13%	0%	0%	0%
25	Mount Storm - Pruntytown	Line	571	29	(542)	574	38	(536)	7%	0%	(6%)	7%	0%	(6%)

Constraint Costs

Table 7-13 Top 25 constraints affecting annual PJM congestion costs (By facility): January through September 2011 (See 2010 SOM, Table 7-13)

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2011 (Jan - Sep)
1	AP South	Interface	500	($8.0)	($220.5)	($1.9)	$210.6	$13.0	$11.9	$4.1	$5.1	$215.7	25%
2	5004/5005 Interface	Interface	500	$58.1	($12.8)	($4.7)	$66.2	$13.5	$16.2	$7.8	$5.1	$71.3	8%
3	Belmont	Transformer	AP	$30.1	($26.3)	($2.2)	$54.3	($3.2)	($2.9)	($1.6)	($1.9)	$52.4	6%
4	West	Interface	500	$66.9	$11.1	($5.3)	$50.5	$0.2	$0.0	$0.1	$0.3	$50.7	6%
5	AEP-DOM	Interface	500	$2.8	($28.6)	$1.9	$33.3	$1.6	$1.1	($0.4)	$0.0	$33.4	4%
6	Electric Jct - Nelson	Line	ComEd	($2.2)	($32.9)	$6.9	$37.7	$0.2	$3.5	($7.7)	($11.0)	$26.7	3%
7	Bedington - Black Oak	Interface	500	$5.4	($19.5)	($2.0)	$22.9	$0.1	$0.0	$0.1	$0.2	$23.1	3%
8	Crete - St Johns Tap	Flowgate	MISO	$1.2	($24.9)	($3.9)	$22.2	$4.7	$3.7	($2.4)	($1.4)	$20.8	2%
9	Clover	Transformer	Dominion	$3.4	($17.5)	$4.6	$25.5	$1.3	$2.4	($7.7)	($8.7)	$16.7	2%
10	Dickerson - Quince Orchard	Line	Pepco	$19.2	$1.1	($1.7)	$16.5	$3.1	$6.3	$2.7	($0.6)	$15.9	2%
11	East	Interface	500	$11.0	($5.5)	($1.1)	$15.4	$0.1	$1.2	$0.1	($1.0)	$14.4	2%
12	Susquehanna	Transformer	PPL	$6.1	($8.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	2%
13	East Frankfort - Crete	Line	ComEd	($0.3)	($13.9)	($1.3)	$12.3	$0.5	$0.4	($1.1)	($1.0)	$11.3	1%
14	Wylie Ridge	Transformer	AP	$36.1	$25.3	$1.8	$12.5	$2.0	$0.9	($2.5)	($1.4)	$11.1	1%
15	Brues - West Bellaire	Line	AEP	$15.1	$0.5	$0.7	$15.3	($1.9)	$1.7	($1.3)	($4.9)	$10.4	1%
16	Waldwick	Transformer	PSEG	$0.7	($1.0)	$2.1	$3.7	($0.1)	$1.2	($12.5)	($13.8)	($10.0)	(1%)
17	Plymouth Meeting - Whitpain	Line	PECO	$3.6	($6.0)	($0.0)	$9.6	$0.1	$0.2	($0.1)	($0.2)	$9.4	1%
18	Cloverdale	Transformer	AEP	$2.0	($5.5)	$1.6	$9.2	$0.3	$0.3	($0.1)	($0.1)	$9.1	1%
19	Oak Grove - Galesburg	Flowgate	MISO	($2.6)	($7.2)	$4.4	$9.0	($1.0)	$3.4	($12.7)	($17.1)	($8.1)	(1%)
20	Bunsonville - Eugene	Flowgate	MISO	($1.6)	($8.2)	$1.4	$8.0	$0.0	$0.0	$0.0	$0.0	$8.0	1%
21	Pleasant Valley - Belvidere	Line	ComEd	($2.5)	($13.1)	$1.7	$12.3	($0.5)	$2.2	($3.1)	($5.7)	$6.5	1%
22	Cloverdale - Lexington	Line	AEP	$4.1	($3.5)	$1.3	$8.8	$2.4	$1.3	($3.8)	($2.7)	$6.2	1%
23	South Mahwah - Waldwick	Line	PSEG	$9.8	($11.6)	($1.3)	$20.2	($0.5)	$5.4	($20.1)	($26.0)	($5.8)	(1%)
24	Lakeview - Pleasant Prairie	Flowgate	MISO	($0.0)	($0.1)	$0.2	$0.3	($0.2)	($0.1)	($5.6)	($5.8)	($5.5)	(1%)
25	Yukon	Transformer	AP	($0.3)	($5.1)	($0.1)	$4.7	$1.4	$0.6	($0.1)	$0.7	$5.4	1%

Table 7-14 Top 25 constraints affecting annual PJM congestion costs (By facility): January through September 2010 (See 2010 SOM, Table 7-14)

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2010 (Jan - Sep)
1	AP South	Interface	500	($11.5)	($351.3)	$1.6	$341.3	$8.5	$5.9	($1.8)	$0.8	$342.1	30%
2	Bedington - Black Oak	Interface	500	$6.3	($76.5)	$2.2	$85.0	$0.1	($0.9)	($0.5)	$0.5	$85.5	8%
3	5004/5005 Interface	Interface	500	$40.9	($34.7)	($0.0)	$75.7	$9.4	$8.3	($1.2)	($0.1)	$75.5	7%
4	Doubs	Transformer	AP	$36.0	($29.7)	$0.4	$66.2	$1.0	$2.1	($2.4)	($3.5)	$62.7	6%
5	AEP-DOM	Interface	500	$9.4	($37.9)	$0.9	$48.3	$0.1	($1.3)	($0.1)	$1.3	$49.6	4%
6	Cloverdale - Lexington	Line	AEP	$15.9	($13.9)	$2.8	$32.7	($2.9)	($3.3)	($5.0)	($4.6)	$28.1	2%
7	East Frankfort - Crete	Line	ComEd	$4.5	($28.8)	$3.9	$37.2	($4.0)	$0.4	($6.6)	($10.9)	$26.3	2%
8	Brandon Shores - Riverside	Line	BGE	$16.8	($10.5)	($0.4)	$26.8	$0.8	$2.3	$0.4	($1.2)	$25.7	2%
9	Mount Storm - Pruntytown	Line	AP	$1.3	($21.2)	$2.1	$24.7	($0.2)	($5.2)	($4.8)	$0.2	$24.9	2%
10	West	Interface	500	$20.8	($1.7)	($0.2)	$22.3	$0.6	$1.2	$0.1	($0.5)	$21.8	2%
11	Tiltonsville - Windsor	Line	AP	$17.6	($2.4)	$1.0	$21.0	($3.3)	$0.5	($0.3)	($4.1)	$16.9	1%
12	Brunner Island - Yorkana	Line	Met-Ed	($2.5)	($15.0)	$0.4	$12.9	$0.8	($1.1)	($0.8)	$1.0	$13.8	1%
13	Belmont	Transformer	AP	$7.1	($6.0)	($0.8)	$12.3	($0.1)	($0.4)	($0.1)	$0.2	$12.4	1%
14	Unclassified	Unclassified	Unclassified	$4.3	($3.1)	$4.7	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	1%
15	Crescent	Transformer	DLCO	$7.5	($3.9)	$0.6	$12.0	$0.2	($0.6)	($0.6)	$0.2	$12.2	1%
16	Crete - St Johns Tap	Flowgate	MISO	($1.4)	($15.8)	($0.2)	$14.2	($1.0)	($0.2)	($1.7)	($2.5)	$11.7	1%
17	Electric Jct - Nelson	Line	ComEd	($9.0)	($33.8)	$7.0	$31.8	($0.3)	$3.6	($16.2)	($20.1)	$11.7	1%
18	Branchburg - Readington	Line	PSEG	$5.7	($7.2)	$0.6	$13.6	($0.5)	$1.6	$0.1	($1.9)	$11.7	1%
19	Clover	Transformer	Dominion	$3.1	($9.9)	$1.8	$14.8	($1.2)	($0.8)	($2.9)	($3.4)	$11.5	1%
20	Pleasant Valley - Belvidere	Line	ComEd	($6.8)	($20.7)	$1.9	$15.8	$0.1	$2.7	($3.6)	($6.1)	$9.7	1%
21	Eddystone - Island Road	Line	PECO	$0.7	($7.7)	$1.1	$9.6	($0.0)	$0.0	$0.0	($0.0)	$9.5	1%
22	Millville - Sleepy Hollow	Line	Dominion	$6.7	($1.9)	($0.1)	$8.5	$0.0	$0.0	$0.0	$0.0	$8.5	1%
23	Hunterstown	Transformer	Met-Ed	$4.2	($3.9)	$0.3	$8.4	$0.1	$0.0	($0.0)	$0.0	$8.5	1%
24	Pleasant Prairie - Zion	Flowgate	MISO	($3.1)	($7.5)	$2.4	$6.7	($0.4)	$1.2	($13.3)	($14.9)	($8.2)	(1%)
25	Limerick	Transformer	PECO	$1.4	($2.0)	($0.1)	$3.2	$0.8	($3.4)	($0.1)	$4.1	$7.3	1%

Table 7-15 Congestion cost by the type of the participant: January through September 2011 (New table)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Financial	$57.9	$9.1	$52.3	$101.1	($33.8)	$5.3	($141.6)	($180.6)	($79.5)
Physical	$311.9	($632.7)	($6.5)	$938.1	$85.0	$88.3	($9.0)	($12.3)	$925.9
Total	$369.8	($623.6)	$45.8	$1,039.2	$51.3	$93.6	($150.5)	($192.9)	$846.4

Table 7-16 Congestion cost by the type of the participant: January through September 2010 (New table)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Financial	$24.6	$4.2	$61.6	$82.0	($54.2)	$16.7	($112.6)	($183.5)	($101.6)
Physical	$286.6	($931.8)	$7.9	$1,226.3	$44.2	$24.7	($5.8)	$13.7	$1,240.0
Total	$311.2	($927.5)	$69.5	$1,308.3	($10.1)	$41.3	($118.4)	($169.8)	$1,138.5

Congestion-Event Summary for MISO Flowgates

Table 7-17 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September 2011 (See 2010 SOM, Table 7-15)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	$1.2	($24.9)	($3.9)	$22.2	$4.7	$3.7	($2.4)	($1.4)	$20.8	2,763	622
2	Oak Grove - Galesburg	($2.6)	($7.2)	$4.4	$9.0	($1.0)	$3.4	($12.7)	($17.1)	($8.1)	1,098	622
3	Bunsonville - Eugene	($1.6)	($8.2)	$1.4	$8.0	$0.0	$0.0	$0.0	$0.0	$8.0	1,802	0
4	Lakeview - Pleasant Prairie	($0.0)	($0.1)	$0.2	$0.3	($0.2)	($0.1)	($5.6)	($5.8)	($5.5)	24	294
5	Kenosha - Lakeview	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.5)	($4.9)	($4.7)	($4.7)	0	349
6	Michigan City - Laporte	$0.9	($5.1)	$2.3	$8.3	($1.3)	($1.1)	($3.6)	($3.8)	$4.5	2,323	571
7	Pleasant Prairie - Zion	($0.8)	($1.9)	$2.0	$3.1	($0.0)	($0.4)	($7.9)	($7.5)	($4.4)	839	210
8	Kenosha - Lakeview	$1.3	($1.3)	$0.9	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	989	0
9	Cook - Palisades	$0.9	($2.3)	$0.2	$3.5	$0.0	$0.0	($0.2)	($0.2)	$3.2	419	9
10	Benton Harbor - Palisades	$0.7	($0.1)	$0.2	$1.0	$1.0	$1.0	($2.9)	($2.9)	($1.9)	67	120
11	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.1	$0.3	($1.6)	($1.8)	($1.8)	0	49
12	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($1.7)	($1.7)	($1.7)	0	76
13	Rising	($1.0)	($4.2)	($0.2)	$3.0	($0.3)	$0.7	($3.3)	($4.4)	($1.3)	947	172
14	Rantoul Jct - Sidney	($0.3)	($1.3)	$0.1	$1.1	$0.5	($0.0)	($0.3)	$0.2	$1.3	62	113
15	Rantoul - Rantoul Jct	($0.2)	($1.6)	$0.3	$1.6	$0.0	$0.0	($0.4)	($0.4)	$1.2	313	139
16	Burr Oak	$0.4	($0.7)	$0.0	$1.1	$0.3	($0.1)	($0.4)	($0.1)	$1.1	147	27
17	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	$0.5	$0.3	($1.2)	($1.0)	($1.0)	0	16
18	Babcock - Stillwell	($0.8)	($1.6)	($0.2)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	295	0
19	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.7)	($0.6)	($0.6)	0	13
20	Cumberland - Bush	($0.1)	($2.5)	$0.8	$3.1	$0.2	$0.2	($2.5)	($2.5)	$0.6	936	0

Table 7-18 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September 2010 (See 2010 SOM, Table 7-16)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($1.4)	($15.8)	($0.2)	$14.2	($1.0)	($0.2)	($1.7)	($2.5)	$11.7	800	245
2	Pleasant Prairie - Zion	($3.1)	($7.5)	$2.4	$6.7	($0.4)	$1.2	($13.3)	($14.9)	($8.2)	1,098	306
3	Rising	$0.3	($4.2)	$0.6	$5.1	($0.0)	$0.0	($0.2)	($0.3)	$4.8	776	44
4	Palisades - Vergennes	$2.8	($0.6)	$0.5	$3.9	($0.1)	$0.5	($1.0)	($1.5)	$2.3	235	91
5	Dunes Acres - Michigan City	$0.6	($1.1)	$0.4	$2.1	($0.0)	($0.0)	($0.0)	($0.0)	$2.1	142	3
6	State Line - Wolf Lake	$0.3	($0.6)	$0.6	$1.5	($0.0)	($0.0)	($0.0)	($0.0)	$1.5	376	1
7	Marktown - Inland Steel	$0.6	($1.0)	$0.7	$2.2	($0.9)	$0.8	($1.4)	($3.1)	($0.9)	424	344
8	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.7)	($0.7)	($0.7)	0	24
9	Benton Harbor - Palisades	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	($0.3)	($0.6)	($0.6)	0	32
10	Beaver Valley - Sammis	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.2)	($0.4)	($0.4)	0	8
11	Oak Grove - Galesburg	($0.1)	($0.3)	$0.1	$0.3	($0.0)	$0.1	($0.6)	($0.7)	($0.4)	61	116
12	Michigan City - Laporte	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.3)	($0.4)	($0.4)	0	36
13	Burr Oak	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.2	($0.5)	($0.6)	($0.4)	76	103
14	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	21
15	Cook - Palisades	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.0)	($0.2)	($0.4)	($0.4)	0	9
16	Lanesville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.3)	($0.4)	($0.4)	0	38
17	Stillwell - Dumont	$0.0	($0.2)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	42	0
18	Bunsonville - Eugene	($0.0)	($0.3)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	31	0
19	Palisades - Roosevelt	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.2)	($0.3)	($0.3)	0	30
20	Cumberland - Bush	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.2)	($0.2)	($0.2)	0	18

Congestion-Event Summary for the 500 kV System

Table 7-19 Regional constraints summary (By facility): January through September 2011 (See 2010 SOM, Table 7-17)

				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	($8.0)	($220.5)	($1.9)	$210.6	$13.0	$11.9	$4.1	$5.1	$215.7	3,341	439
2	5004/5005 Interface	Interface	500	$58.1	($12.8)	($4.7)	$66.2	$13.5	$16.2	$7.8	$5.1	$71.3	684	439
3	West	Interface	500	$66.9	$11.1	($5.3)	$50.5	$0.2	$0.0	$0.1	$0.3	$50.7	798	19
4	AEP-DOM	Interface	500	$2.8	($28.6)	$1.9	$33.3	$1.6	$1.1	($0.4)	$0.0	$33.4	1,285	172
5	Bedington - Black Oak	Interface	500	$5.4	($19.5)	($2.0)	$22.9	$0.1	$0.0	$0.1	$0.2	$23.1	624	7
6	East	Interface	500	$11.0	($5.5)	($1.1)	$15.4	$0.1	$1.2	$0.1	($1.0)	$14.4	295	22
7	Central	Interface	500	$1.5	$0.4	($0.1)	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	64	0
8	Doubs - Mount Storm	Line	500	$0.1	($0.2)	($0.0)	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	9	4
9	Harrison - Pruntytown	Line	500	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
10	Dominion East	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	0	38
11	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	9

Table 7-20 Regional constraints summary (By facility): January through September 2010 (See 2010 SOM, Table 7-18)

				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	($11.5)	($351.3)	$1.6	$341.3	$8.5	$5.9	($1.8)	$0.8	$342.1	3,512	1,251
2	Bedington - Black Oak	Interface	500	$6.3	($76.5)	$2.2	$85.0	$0.1	($0.9)	($0.5)	$0.5	$85.5	1,819	47
3	5004/5005 Interface	Interface	500	$40.9	($34.7)	($0.0)	$75.7	$9.4	$8.3	($1.2)	($0.1)	$75.5	1,379	561
4	AEP-DOM	Interface	500	$9.4	($37.9)	$0.9	$48.3	$0.1	($1.3)	($0.1)	$1.3	$49.6	471	89
5	West	Interface	500	$20.8	($1.7)	($0.2)	$22.3	$0.6	$1.2	$0.1	($0.5)	$21.8	161	58
6	Harrison - Pruntytown	Line	500	$1.9	($4.1)	$0.8	$6.9	($0.5)	($0.3)	($2.7)	($2.9)	$4.0	231	223
7	East	Interface	500	$1.4	($1.8)	$0.0	$3.2	($0.0)	$0.0	$0.0	($0.0)	$3.2	154	1
8	Central	Interface	500	$1.1	($0.2)	$0.1	$1.4	$0.1	$0.1	($0.1)	($0.0)	$1.3	116	13
9	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	$0.5	$0.7	($0.1)	($0.3)	($0.3)	0	45
10	Harrison Tap - North Longview	Line	500	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	6	0
11	Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	1

Zonal Congestion

Summary

Table 7-21 Congestion cost summary (By control zone): January through September 2011 (See 2010 SOM, Table 7-19)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$41.4	$12.6	$0.7	$29.5	($0.2)	$0.1	($1.0)	($1.3)	$28.1
AEP	($52.3)	($249.0)	$12.2	$208.9	$2.2	$27.0	($20.8)	($45.6)	$163.3
AP	$0.3	($135.6)	($3.8)	$132.1	$4.0	$5.2	($0.7)	($1.9)	$130.1
ATSI	($47.2)	($25.1)	$1.5	($20.7)	($1.8)	$7.3	($4.2)	($13.3)	($34.0)
BGE	$113.4	$67.5	$6.7	$52.5	$3.1	$0.9	($10.3)	($8.2)	$44.4
ComEd	($337.3)	($533.6)	$1.0	$197.3	$40.5	$27.2	($22.8)	($9.5)	$187.8
DAY	($13.7)	($22.6)	$0.7	$9.6	$2.2	$5.0	($3.5)	($6.3)	$3.3
DLCO	($36.5)	($57.9)	($0.2)	$21.2	($3.0)	$0.4	($0.5)	($4.0)	$17.2
DPL	$60.0	$19.9	$1.2	$41.3	$0.5	$3.6	($2.1)	($5.2)	$36.1
Dominion	$100.8	($45.1)	$20.4	$166.3	($7.9)	$1.7	($34.5)	($44.1)	$122.1
External	($36.3)	($36.2)	($10.7)	($10.9)	($3.4)	($15.6)	($7.3)	$4.9	($6.0)
JCPL	$66.1	$25.8	$0.5	$40.8	$4.2	$1.2	($0.8)	$2.2	$43.0
Met-Ed	$37.0	$43.8	$0.4	($6.4)	$2.1	$0.6	($0.7)	$0.9	($5.5)
PECO	$125.7	$114.9	$0.9	$11.7	$0.4	$4.7	($1.1)	($5.4)	$6.3
PENELEC	($21.1)	($78.5)	($0.5)	$56.9	$2.7	$6.0	($0.9)	($4.2)	$52.7
PPL	$105.5	$111.1	$4.8	($0.8)	$8.0	$2.4	($3.3)	$2.2	$1.4
PSEG	$120.1	$87.2	$5.5	$38.4	$1.0	$16.7	($30.3)	($46.0)	($7.6)
Pepco	$141.9	$77.3	$4.6	$69.2	($3.3)	($1.9)	($5.6)	($6.9)	$62.3
RECO	$2.1	($0.2)	$0.1	$2.4	$0.0	$1.0	($0.1)	($1.1)	$1.3
Total	$369.8	($623.6)	$45.8	$1,039.2	$51.3	$93.6	($150.5)	($192.9)	$846.4

Table 7-22 Congestion cost summary (By control zone): January through September 2010 (See 2010 SOM, Table 7-20)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$33.6	$12.0	$0.2	$21.8	($0.7)	($1.0)	($0.1)	$0.2	$22.0
AEP	($122.2)	($278.3)	$12.0	$168.1	($9.8)	$20.5	($16.5)	($46.9)	$121.3
AP	($4.0)	($241.6)	$1.7	$239.3	$11.3	$20.4	($3.9)	($13.0)	$226.2
BGE	$157.2	$90.2	$6.0	$73.0	$10.8	($3.6)	($7.9)	$6.5	$79.5
ComEd	($325.6)	($539.7)	$4.7	$218.7	($23.9)	$8.9	($13.9)	($46.6)	$172.1
DAY	($14.8)	($23.4)	$6.1	$14.7	$1.3	$1.2	($7.0)	($6.9)	$7.8
DLCO	($72.0)	($110.0)	($0.2)	$37.8	($9.2)	($0.6)	$0.2	($8.4)	$29.4
DPL	$57.2	$20.5	$0.7	$37.4	($0.5)	$1.1	($1.0)	($2.7)	$34.7
Dominion	$192.1	($30.6)	$12.7	$235.4	($3.8)	($6.0)	($14.5)	($12.3)	$223.1
External	($144.5)	($153.4)	($5.5)	$3.4	$7.0	($18.5)	($26.4)	($0.9)	$2.5
JCPL	$56.4	$20.2	$0.4	$36.6	$2.8	($0.2)	($0.5)	$2.5	$39.0
Met-Ed	$50.9	$37.2	$0.9	$14.6	($0.8)	($0.1)	($1.2)	($1.8)	$12.8
PECO	$48.8	$54.4	$0.3	($5.3)	($2.6)	$0.9	($0.9)	($4.3)	($9.6)
PENELEC	($61.3)	($142.2)	$0.3	$81.1	$17.4	$6.0	$0.0	$11.5	$92.6
PPL	$74.6	$84.0	$3.0	($6.3)	$9.6	$7.5	($0.6)	$1.4	($5.0)
PSEG	$97.0	$74.4	$21.4	$44.0	($2.1)	$11.8	($18.4)	($32.2)	$11.8
Pepco	$284.9	$198.7	$4.9	$91.2	($17.5)	($7.0)	($5.7)	($16.2)	$75.0
RECO	$2.9	$0.2	$0.0	$2.7	$0.6	($0.0)	($0.0)	$0.6	$3.3
Total	$311.2	($927.5)	$69.5	$1,308.3	($10.1)	$41.3	($118.4)	($169.8)	$1,138.5

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs were available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs from the inception of locational marginal pricing (LMP) on April 1, 1998. Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[1] Since then, all PJM members have been eligible to purchase FTRs in auctions. Network service and firm point-to-point transmission service customers can take allocated ARRs or convert the ARRs to the underlying FTRs through a self scheduling process. 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.

Firm transmission service customers have access to ARRs/FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission service customers receive requested ARRs/FTRs to the extent that they are consistent both with the physical capability of the transmission system and with ARR/FTR requests of other eligible customers.

The *2011 Quarterly State of the Market Report for PJM: January through September* focuses on the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2010 to 2011 planning period which covers June 1, 2010, through May 31, 2011, and the 2011 to 2012 planning period which covers June 1, 2011, through May 31, 2012.

1 87 FERC ¶ 61,054 (1999).

Table 8-1 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 in the first nine months of 2011.
- 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.

Highlights

- On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined the PJM footprint. Network Service users and Firm Transmission Customers in the ATSI Control Zone participated in the Annual ARR Allocation and the Annual FTR Auction for the 2011 to 2012 planning period.
- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2011 to 2012 planning period increased 84 percent from 580,753 MW, to 1,067,014 MW, compared to the first four months of the 2010 to 2011 planning period.

- FTRs were paid at 84.9 percent of the target allocation level for the full 2010 to 2011 planning period and 90.9 percent for the first four months of the 2011 to 2012 planning period.

- FTRs were profitable overall and were profitable for both physical and financial entities in the first nine months of 2011. Total FTR profits were $363.7 million for physical entities and $147.2 million for financial entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any 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. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. The most recent Long Term FTR Auction was conducted during the 2010 to 2011 planning period and covers three consecutive planning periods between 2011 and 2014. In addition, PJM administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. FTR options are not available in the Long Term FTR Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. 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.

  Market participants can also sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first four months (June through September 2011) of the 2011 to 2012 planning period, total FTR sell offers were 2,527,945 MW.

- **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.[2] On this basis, PJM has limited the maximum number of bids that could be submitted by a participant for any individual period in an auction to 20,000 bids. Effective with the September 2011 Monthly FTR Auction, PJM implemented new limits restricting the maximum number of bids for any individual period in an auction to 10,000 bids. For example, a participant in the September 2011 Monthly FTR Auction can place 10,000 bids for each of the six periods of September, October, November, Q2, Q3 and Q4 for a total of 60,000 bids. "This enforcement is necessary due to the increased participation in the FTR markets which has resulted in degrading system performance in the FTR Auction clearing process."[3] The number of participants submitting more than 10,000 bids has ranged from two, in the 2010/2011 annual auction, to six, in recent monthly auctions. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2011 to 2012 (June through September 2011) planning period increased 62 percent from 4,924,599 MW, during the same time period of the prior planning period, to 7,977,088 MW.

  Figure 8-1 shows the bid, net bid and cleared volume from the Annual and Monthly FTR auctions for June 2003 through September 2011. The net bid volume is the net volume of all buy bids minus all sell offers. The bid and cleared volume for Annual FTR auctions are included in the first month of each planning period. For example, the volume for the 2010 to 2011 Annual FTR Auction is shown in June 2010, which also includes the June 2010 Monthly FTR Auction volume. The increase in volume appearing every year in June is the additional volume from the Annual FTR Auction for that planning period.

- **FTR Credit Issues.** There were no participants that defaulted during the first nine months of 2011.

2 OA Schedule 1 § 7.3.5(d).
3 See Messages section in eFTR within the PJM eSuite application <https://esuite.pjm.com/mui/> Accessed November 4, 2011.

On September 15, 2011, the FERC conditionally approved PJM's proposed revisions to its credit policy filed in compliance with FERC's Order No. 741, which required tighter credit standards for all RTOs.[4] The FERC determined that PJM was already compliant in a number of respects, and, effective October 1, 2011, permitted PJM to implement the following changes: the maximum aggregate unsecured limit for affiliated groups was reduced to $50 million from $150 million; minimum financial criteria for participation in PJM market; and PJM is now required to explain in writing application of its Material Adverse Change provisions.[5]

PJM plans to file in November, 2011, in response to the September 15th order, provisions that would: include Seller Credit (including RPM Seller Credit) in the calculation of an individual member's and an affiliated group's unsecured credit limit; eliminate Seller Credit as a means to fulfill FTR credit requirements;[6] and revise the Minimum Criteria for Participation officer certification form to clarify the term "hedging" as it pertains to FTR transactions and "expand the applicability of the risk management policies, procedures and practices verification process." As a result of the extended period of compliance, PJM states that it will require submittal of officer certification forms and risk management procedures during the first four months of 2012.[7]

Smaller financial traders have asserted that the new requirements may exclude them from the markets and negatively impact liquidity.[8]

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2011 to 2012 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 low 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 only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction. In order to provide additional information about 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. Financial entities purchased 87 percent of prevailing flow and 86 percent of counter flow FTRs in the Monthly Balance of Planning Period Auctions for the first nine months of 2011. The net position of all FTRs, including all auctions, is calculated for every organization each day. The organization's net position is the difference between all FTR buys and FTR sells from all relevant auctions and bilateral trades for each day. The data is summarized for the first nine months of 2011 to show ownership patterns by FTR direction. Financial entities owned 65 percent of all prevailing and counter flow FTRs, including 60 percent of all prevailing flow FTRs and 77 percent of all counter flow FTRs during the same time period.

Market Performance

- **Volume.** For the first four months of the 2011 to 2012 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,067,014 MW (13.4 percent) of FTR buy bids and 250,318 MW (9.9 percent) of FTR sell offers.

- **Price.** The weighted-average price paid for buy bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2011 to 2012 planning period was $0.12 per MWh, compared with $0.14 per MWh for the full 12-month 2010 to 2011 planning period.

- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $17.0 million in net revenue for all FTRs during the first four months of the 2011 to 2012 planning period. This is a $5.86 million increase from the comparable time period in the 2010 to 2011 planning period.

- **Revenue Adequacy.** FTRs were 84.9 percent revenue adequate for the 2010 to 2011 planning period. FTRs were paid at 90.9 percent of the target allocation level for the first four months of the 2011 to 2012 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $452.5 million of FTR revenues during the first four months of the 2011 to 2012 planning period and $1,431.5 million during the 2010 to 2011 planning period. For the first four months of the 2011 to 2012 planning period, the top

4 *PJM Interconnection, L.L.C.*, 136 FERC ¶61,190; *Credit Reforms in Organized Wholesale Electric Markets*, Order No. 741, FERC Stats. & Regs. ¶31,317 (2010), *order on reh'g*, Order No. 741-A, FERC Stats. & Regs. ¶31,320, *reh'g denied*, Order No. 741-B, 135 FERC ¶61,242 (2011).

5 Id.

6 *See* OATT Attachment Q (PJM Credit Policy). Section II.C provides for all markets other than RPM: "Participants that have maintained a Net Sell Position for each of the prior 12 months are eligible for Seller Credit, which is an additional form of Unsecured Credit." Section IV.E. provides RPM seller credit provisions, stating: "If a supplier has a history of being a net seller into PJM markets, on average, over the last 12 months, then PJM Settlement will count as available Unsecured Credit twice the average of that participant's total net monthly PJM Settlement bills over the past 12 months."

7 Email from Suzanne Daugherty, PJM Vice President and CFO to Members, "Summary of FERC Order on PJM's Credit Order 741 Compliance Filing" (September 16, 2011) ("PJM Email Summary").

8 *See* FERC Docket No. ER11-3972.

sink and top source with the highest positive FTR target allocations were the AEP without Mon Power aggregate[9] and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were AEP without Mon Power and the Kammer aggregate.

- **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 and were profitable for both physical entities and financial entities in the first nine months of 2011. FTR profits tended to increase in the summer and winter months when congestion was higher and decrease in the shoulder months when congestion was lower.

Auction Revenue Rights

Market Structure

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. 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. There were 14,676 MW of ARRs associated with approximately $254,300 of revenue that were reassigned in the first four months of the 2011 to 2012 planning period. There were 51,645 MW of ARRs associated with approximately $1,016,500 of revenue that were reassigned for the full twelve months of the 2010 to 2011 planning period.

Market Performance

On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. Network Service Users and Firm Transmission Customers in the ATSI Control Zone participated in the 2011 to 2012 Annual ARR Allocation. For a transitional period, those customers that receive, and pay for, firm transmission service that sources or sinks in newly integrated PJM control zones may elect to receive a direct allocation of FTRs instead of an allocation of ARRs. This transitional period covers the succeeding two Annual FTR Auctions after the integration of the new zone into PJM.

- **Revenue Adequacy.** During the 2011 to 2012 planning period, the ARR target allocations were $982.9 million while PJM collected $1,082.5 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through September 30, 2011, making ARRs revenue adequate. For the 2010 to 2011 planning period, the ARR target allocations were $1,029.3 million while PJM collected $1,097.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

  Figure 8-4 shows the original FTR payout ratio with adjustments by month, excluding excess revenue distribution, for January 2004 through September 2011. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Unlike Figure 8-4, the FTR payout ratios in Figure 8-5 include excess revenue distributions across months within the planning period. Excess revenues from one month are distributed to prior or future months that were revenue deficient.

- **ARRs and FTRs as a Hedge against Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The effectiveness of ARRs as a hedge 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 2010 to 2011 planning period, all ARRs and FTRs hedged more than 96.9 percent of the congestion costs within PJM. During the first four months of the 2011 to 2012 planning period, total ARR and FTR revenues hedged more than 100 percent of the congestion costs within PJM.

- **ARRs and FTRs as a Hedge against Total Energy Costs.** The value provided by ARRs and FTRs can also be measured by comparing the value of the ARRs and FTRs that sink in a zone to the cost of real time energy in the zone. The total value of ARRs plus FTRs was 3.0 percent of the total real time energy charges in the first nine months of 2011.

Conclusion

The annual ARR allocation and the FTR auctions provide market participants with the opportunity to hedge positions or to speculate. The

9 The AEP without Mon Power aggregate is the AEP Control Zone without Monongahela Power.

Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR auction results for the 2011 to 2012 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs.

FTRs were paid at 84.9 percent of the target allocation level for the 2010 to 2011 planning period. FTRs for the first four months of the 2011 to 2012 planning period were paid at 90.9 percent of the target allocation level. Revenue adequacy for a planning period is not final until the end of the period. Total congestion revenues are allocated to FTR holders based on FTR target allocations.[10] Revenue inadequacy occurs when total congestion, which is comprised of day-ahead congestion plus balancing congestion, is less than the FTR target allocation. There has been significant underfunding since the spring of 2010. PJM and its stakeholders identified discrepancies between auction modeling and actual system conditions as the primary drivers of the underfunding. These discrepancies included outages not modeled in the annual or monthly auctions and additional transmission switching decisions not incorporated in the model. The impact of including balancing congestion in the calculation of revenues was also noted.[11] Although the annual FTR auction represents the entire year, the auction model reflects the PJM system for a single point in time. PJM must evaluate transmission line outage schedules and thermal operating limits for transmission lines for inclusion in the model for the Annual FTR Auction. FTR revenue adequacy is not guaranteed nor should it be. PJM should model the system as accurately as possible and participants should bid prices that reflect their evaluations of the expected profitability of FTRs.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion to target allocations.

The total of ARR and FTR revenues hedged 96.9 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2010 to 2011 planning period and more than 100 percent of the congestion costs in PJM during the first four months of the 2011 to 2012 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of ARR and FTR holders, their revenues or those paying congestion.

Financial Transmission Rights

Market Structure

Patterns of Ownership

Table 8-2 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September 2011 (See 2010 SOM, Table 8-6)

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	13.0%	13.8%	13.3%
	Financial	87.0%	86.2%	86.7%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	28.3%	21.7%	27.4%
	Financial	71.7%	78.3%	72.6%
	Total	100.0%	100.0%	100.0%

Table 8-3 Daily FTR net position ownership by FTR direction: January through September 2011 (See 2010 SOM, Table 8-7)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	39.6%	22.7%	35.1%
Financial	60.4%	77.3%	64.9%
Total	100.0%	100.0%	100.0%

10 PJM Financial Transmission Rights Task Force (FTRTF), <http://pjm.com/committees-and-groups/task-forces/ftrtf.aspx>.
11 The Market Implementation Committee (MIC) approved the creation of the Financial Transmission Rights Task Force (FTRTF) to investigate the causes of the FTR revenue inadequacy that occurred in the 2010 to 2011 Planning Period and identify potential improvements that could be made to minimize the revenue inadequacy going forward.

Market Performance

Volume

Table 8-4 Monthly Balance of Planning Period FTR Auction market volume: January through September 2011 (See 2010 SOM, Table 8-11)

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-11	Obligations	Buy bids	189,084	1,101,808	164,743	15.0%	937,065	85.0%
		Sell offers	50,981	261,888	28,189	10.8%	233,699	89.2%
	Options	Buy bids	1,040	105,293	8,691	8.3%	96,602	91.7%
		Sell offers	2,927	43,161	12,380	28.7%	30,781	71.3%
Feb-11	Obligations	Buy bids	185,625	1,090,475	181,977	16.7%	908,497	83.3%
		Sell offers	41,609	220,079	20,957	9.5%	199,122	90.5%
	Options	Buy bids	959	93,909	9,372	10.0%	84,536	90.0%
		Sell offers	2,555	33,140	9,643	29.1%	23,497	70.9%
Mar-11	Obligations	Buy bids	192,349	1,154,132	216,165	18.7%	937,967	81.3%
		Sell offers	48,727	256,121	30,492	11.9%	225,629	88.1%
	Options	Buy bids	1,026	96,152	7,254	7.5%	88,898	92.5%
		Sell offers	2,351	41,200	10,587	25.7%	30,613	74.3%
Apr-11	Obligations	Buy bids	149,735	847,575	164,278	19.4%	683,297	80.6%
		Sell offers	37,737	220,966	22,108	10.0%	198,858	90.0%
	Options	Buy bids	919	66,008	5,387	8.2%	60,621	91.8%
		Sell offers	1,834	32,136	9,327	29.0%	22,810	71.0%
May-11	Obligations	Buy bids	138,353	741,926	189,851	25.6%	552,075	74.4%
		Sell offers	27,642	122,217	13,661	11.2%	108,556	88.8%
	Options	Buy bids	759	20,612	2,485	12.1%	18,127	87.9%
		Sell offers	1,184	19,631	9,065	46.2%	10,566	53.8%
Jun-11	Obligations	Buy bids	332,116	1,924,420	312,144	16.2%	1,612,276	83.8%
		Sell offers	135,073	585,528	40,839	7.0%	544,689	93.0%
	Options	Buy bids	7,625	256,153	11,013	4.3%	245,140	95.7%
		Sell offers	18,794	103,002	24,097	23.4%	78,904	76.6%
Jul-11	Obligations	Buy bids	343,986	2,085,575	286,143	13.7%	1,799,432	86.3%
		Sell offers	124,629	554,483	37,933	6.8%	516,549	93.2%
	Options	Buy bids	3,239	147,732	13,337	9.0%	134,395	91.0%
		Sell offers	12,897	76,029	20,259	26.6%	55,770	73.4%

Table 8-4 Monthly Balance of Planning Period FTR Auction market volume: January through September 2011 (See 2010 SOM, Table 8-11) [continued]

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
Aug-11	Obligations	Buy bids	310,562	1,830,992	252,468	13.8%	1,578,524	86.2%
		Sell offers	117,597	529,879	40,335	7.6%	489,545	92.4%
	Options	Buy bids	3,070	150,896	6,736	4.5%	144,160	95.5%
		Sell offers	10,680	66,968	14,427	21.5%	52,541	78.5%
Sep-11	Obligations	Buy bids	255,744	1,352,484	180,231	13.3%	1,172,252	86.7%
		Sell offers	111,846	538,916	54,686	10.1%	484,230	89.9%
	Options	Buy bids	3,368	228,757	4,942	2.2%	223,815	97.8%
		Sell offers	10,816	73,140	17,741	24.3%	55,399	75.7%
2010/2011*	Obligations	Buy bids	2,378,154	12,888,263	1,975,624	15.3%	10,912,639	84.7%
		Sell offers	709,605	3,448,995	311,688	9.0%	3,137,308	91.0%
	Options	Buy bids	16,090	1,403,272	67,536	4.8%	1,335,736	95.2%
		Sell offers	60,091	568,271	147,251	25.9%	421,021	74.1%
2011/2012**	Obligations	Buy bids	1,242,408	7,193,470	1,030,987	14.3%	6,162,484	85.7%
		Sell offers	489,145	2,208,806	173,794	7.9%	2,035,012	92.1%
	Options	Buy bids	17,302	783,537	36,028	4.6%	747,510	95.4%
		Sell offers	53,187	319,139	76,524	24.0%	242,615	76.0%

* Shows twelve months for 2010/2011; ** Shows four months ended 30-Sep-2011 for 2011/2012

Table 8-5 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January through September 2011 (See 2010 SOM, Table 8-12)

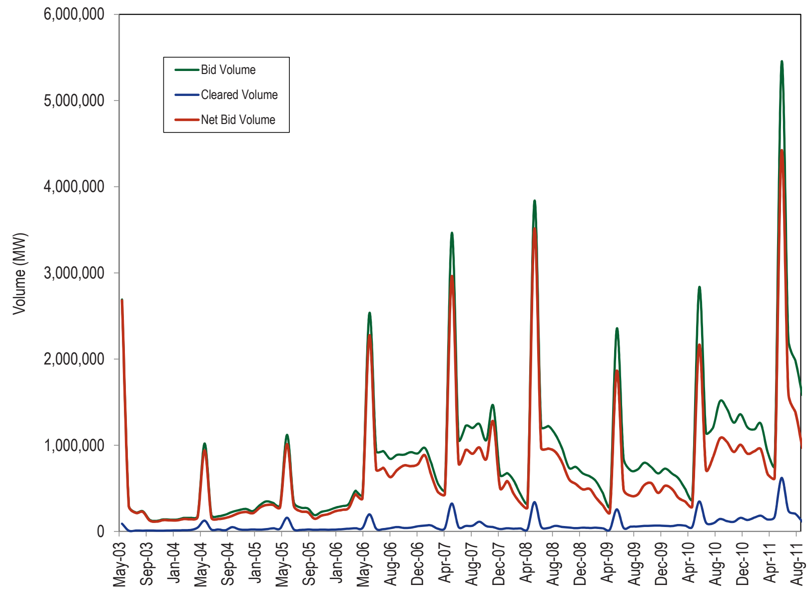
Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-11	Bid	677,552	197,260	140,265				192,024	1,207,101
	Cleared	134,232	18,200	8,548				12,454	173,434
Feb-11	Bid	705,015	157,482	139,776				182,111	1,184,383
	Cleared	156,562	11,243	11,107				12,438	191,350
Mar-11	Bid	774,291	206,225	205,539				64,228	1,250,283
	Cleared	173,607	22,830	20,602				6,380	223,419
Apr-11	Bid	698,577	215,007						913,583
	Cleared	153,834	15,832						169,666
May-11	Bid	762,538							762,538
	Cleared	192,336							192,336
Jun-11	Bid	893,961	247,465	245,244	87,002	241,008	219,128	246,765	2,180,573
	Cleared	176,087	28,040	27,497	10,733	28,673	26,805	25,321	323,157
Jul-11	Bid	924,620	300,178	148,980		293,107	287,862	278,560	2,233,307
	Cleared	171,384	28,868	14,197		27,365	31,676	25,990	299,480
Aug-11	Bid	892,507	181,881	169,691		238,458	248,517	250,833	1,981,888
	Cleared	168,550	16,915	15,175		15,479	20,858	22,227	259,204
Sep-11	Bid	743,395	186,272	182,067		49,451	206,242	213,814	1,581,240
	Cleared	120,684	16,207	15,317		3,983	14,362	14,621	185,173

Table 8-6 Secondary bilateral FTR market volume: Planning periods 2010 to 2011 and 2011 to 2012[12] (See 2010 SOM, Table 8-13)

Planning Period	Hedge Type	Class Type	Volume (MW)
2010/2011	Obligation	24-Hour	1,729
		On Peak	10,578
		Off Peak	12,740
		Total	25,047
	Option	24-Hour	20
		On Peak	0
		Off Peak	0
		Total	20
2011/2012*	Obligation	24-Hour	218
		On Peak	604
		Off Peak	336
		Total	1,158
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0

* Shows four months ended 30-Sep-2011

Figure 8-1 Annual and Monthly FTR Auction bid and cleared volume: June 2003 through September 2011 (New Figure)



12 The 2011 to 2012 planning period covers bilateral FTRs that are effective for any time between June 1, 2011 through September 30, 2011, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Price

Table 8-7 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January through September 2011 (See 2010 SOM, Table 8-16)

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-11	$0.13	$0.36	$0.02				$0.28	$0.17
Feb-11	$0.08	$0.13	$0.11				$0.18	$0.10
Mar-11	$0.09	$0.16	$0.15				$0.04	$0.09
Apr-11	$0.07	$0.23						$0.08
May-11	$0.06							$0.06
Jun-11	$0.06	$0.15	$0.07	$0.33	$0.12	$0.20	$0.13	$0.13
Jul-11	$0.10	$0.15	$0.03		$0.01	$0.14	$0.02	$0.08
Aug-11	$0.12	$0.04	$0.10		$0.17	$0.20	$0.13	$0.14
Sep-11	$0.11	$0.24	$0.18		$0.20	$0.24	$0.15	$0.16

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 8-8 Monthly Balance of Planning Period FTR Auction revenue: January through September 2011 (See 2010 SOM, Table 8-19)

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-11	Obligations	Buy bids	($1,205,888)	$7,104,026	$6,539,294	$12,437,433
		Sell offers	$1,138,221	$2,625,465	$4,050,289	$7,813,975
	Options	Buy bids	$0	$136,353	$87,800	$224,153
		Sell offers	$0	$1,812,131	$686,209	$2,498,340
Feb-11	Obligations	Buy bids	($36,220)	$4,296,859	$3,345,841	$7,606,480
		Sell offers	$587,026	$1,938,472	$2,305,072	$4,830,570
	Options	Buy bids	$0	$126,188	$25,671	$151,859
		Sell offers	$1,947	$1,218,343	$389,391	$1,609,682
Mar-11	Obligations	Buy bids	($101,074)	$4,605,081	$3,368,274	$7,872,281
		Sell offers	$423,197	$2,274,909	$1,933,265	$4,631,371
	Options	Buy bids	$14,085	$292,986	$178,090	$485,161
		Sell offers	$5,149	$1,231,751	$454,338	$1,691,239
Apr-11	Obligations	Buy bids	$374,217	$2,884,005	$1,629,459	$4,887,681
		Sell offers	$677,941	$1,461,719	$878,890	$3,018,551
	Options	Buy bids	$4,569	$88,824	$54,691	$148,084
		Sell offers	$3,727	$721,783	$403,883	$1,129,392

Table 8-8 Monthly Balance of Planning Period FTR Auction revenue: January through September 2011 (See 2010 SOM, Table 8-19) [continued]

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
May-11	Obligations	Buy bids	$451,258	$2,063,976	$1,214,403	$3,729,637
		Sell offers	$210,714	$1,074,632	$567,818	$1,853,164
	Options	Buy bids	$0	$91,362	$181,717	$273,078
		Sell offers	$185	$539,763	$393,717	$933,665
Jun-11	Obligations	Buy bids	$1,960,494	$13,115,229	$8,318,764	$23,394,487
		Sell offers	$5,175,453	$5,288,319	$2,797,969	$13,261,740
	Options	Buy bids	$0	$186,515	$192,243	$378,758
		Sell offers	$0	$3,103,330	$2,147,165	$5,250,495
Jul-11	Obligations	Buy bids	$2,169,505	$6,367,118	$4,209,356	$12,745,978
		Sell offers	($2,192,924)	$4,283,630	$2,794,481	$4,885,187
	Options	Buy bids	$51,761	$1,117,027	$549,087	$1,717,875
		Sell offers	$0	$2,862,215	$1,919,105	$4,781,320
Aug-11	Obligations	Buy bids	$452,651	$12,262,357	$5,644,491	$18,359,499
		Sell offers	$331,875	$7,816,757	$3,706,720	$11,855,353
	Options	Buy bids	$0	$596,709	$482,609	$1,079,318
		Sell offers	$0	$2,652,228	$1,190,174	$3,842,402
Sep-11	Obligations	Buy bids	$1,787,959	$8,393,963	$3,116,850	$13,298,772
		Sell offers	$276,769	$5,516,851	$2,229,736	$8,023,356
	Options	Buy bids	$9,087	$722,750	$580,167	$1,312,004
		Sell offers	$0	$2,173,747	$1,218,088	$3,391,835
2010/2011*	Obligations	Buy bids	$4,299,849	$72,821,616	$53,395,404	$130,516,869
		Sell offers	$8,535,079	$35,362,863	$29,972,637	$73,870,579
	Options	Buy bids	$41,745	$2,698,623	$2,098,161	$4,838,530
		Sell offers	$1,878,318	$20,472,308	$14,658,870	$37,009,496
2011/2012**	Obligations	Buy bids	$6,370,609	$40,138,666	$21,289,461	$67,798,736
		Sell offers	$3,591,172	$22,905,558	$11,528,906	$38,025,636
	Options	Buy bids	$60,848	$2,623,000	$1,804,107	$4,487,955
		Sell offers	$0	$10,791,520	$6,474,532	$17,266,052

* Shows twelve months for 2010/2011; ** Shows four months ended 30-Sep-2011 for 2011/2012

Figure 8-2 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2011 to 2012 through September 30, 2011 (See 2010 SOM, Figure 8-7)

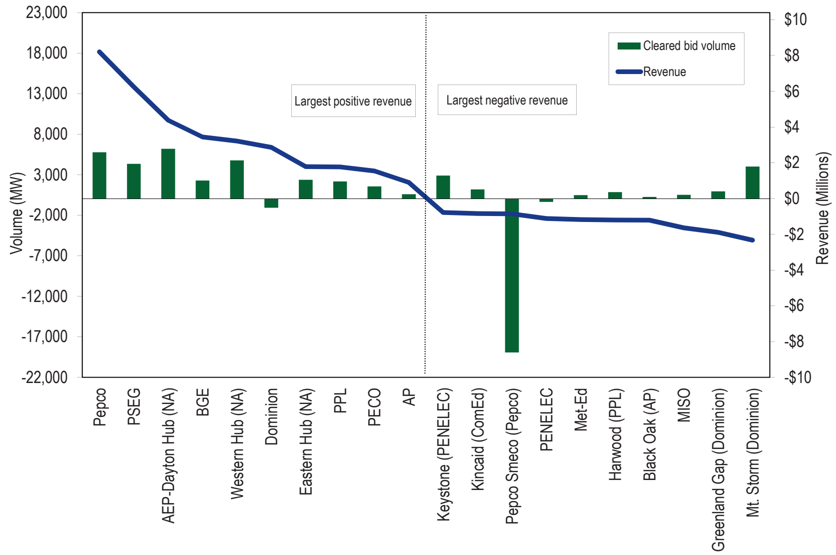
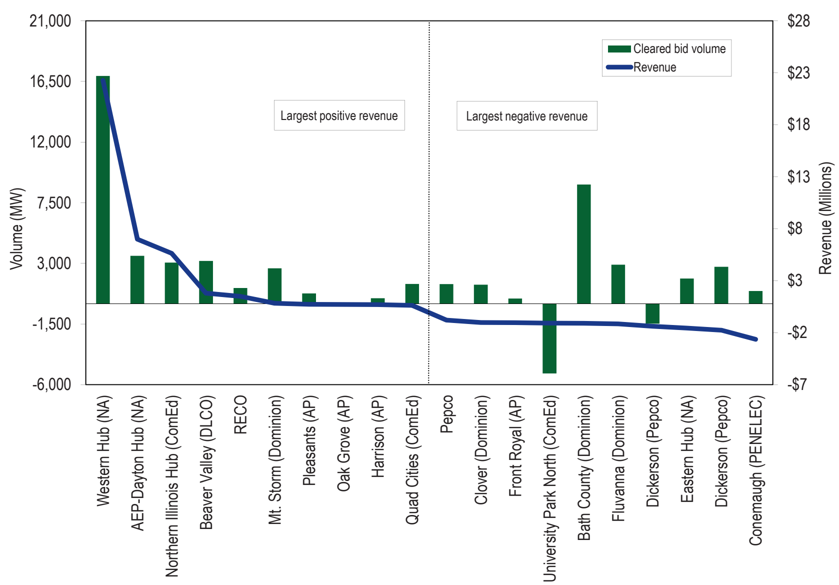


Figure 8-3 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2011 to 2012 through September 30, 2011 (See 2010 SOM, Figure 8-8)



Revenue Adequacy

Table 8-9 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012 (See 2010 SOM, Table 8-20)

Accounting Element	2010/2011	2011/2012*
ARR information		
ARR target allocations	$1,031.0	$327.6
FTR auction revenue	$1,097.8	$364.9
ARR excess	$66.9	$37.2
FTR targets		
FTR target allocations	$1,687.6	$498.4
Adjustments:		
Adjustments to FTR target allocations	($1.8)	($0.8)
Total FTR targets	$1,685.8	$497.6
FTR revenues		
ARR excess	$66.9	$37.2
Competing uses	$0.1	$0.0
Congestion		
Net Negative Congestion (enter as negative)	($59.5)	($12.6)
Hourly congestion revenue	$1,464.9	$452.5
MISO M2M (credit to PJM minus credit to MISO)	($47.8)	($24.5)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($0.8)	($0.1)
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$4.6	$0.0
Other adjustments to FTR revenues	$0.5	($0.0)
Total FTR revenues	$1,428.8	$452.5
Excess revenues distributed to other months	($4.6)	$0.0
Net Negative Congestion charged to DA Operating Reserves	$7.3	$0.0
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	$1,431.5	$452.5
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,432.4	$452.6
Remaining deficiency	$254.2	$45.2

* Shows four months ended 30-Sep-11

Table 8-10 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012 through September 30, 2011[13] (See 2010 SOM, Table 8-21)

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-10	$194.2	$196.1	98.0%	$194.2	99.0%	($1.9)
Jul-10	$275.0	$273.0	100.7%	$273.0	100.0%	$0.0
Aug-10	$111.3	$119.2	93.3%	$111.3	93.4%	($7.9)
Sep-10	$116.7	$165.3	70.2%	$116.7	70.6%	($48.5)
Oct-10	$52.4	$67.4	77.5%	$52.4	77.8%	($14.9)
Nov-10	$51.5	$80.0	63.9%	$51.5	64.4%	($28.5)
Dec-10	$185.0	$251.1	73.3%	$185.0	73.7%	($66.2)
Jan-11	$245.4	$249.5	98.4%	$245.4	98.4%	($4.0)
Feb-11	$79.4	$93.0	85.2%	$79.4	85.4%	($13.6)
Mar-11	$48.2	$45.6	105.7%	$45.6	100.0%	$0.0
Apr-11	$39.4	$73.2	53.9%	$39.4	53.9%	($33.8)
May-11	$37.5	$72.5	51.8%	$37.5	51.8%	($34.9)
Summary for Planning Period 2010 to 2011						
Total	$1,431.5	$1,685.8		$1,431.5	84.9%	($254.2)
Jun-11	$134.6	$154.6	87.1%	$134.6	87.1%	($20.0)
Jul-11	$177.8	$181.4	98.0%	$177.8	98.0%	($3.6)
Aug-11	$70.7	$73.4	96.3%	$70.7	96.3%	($2.7)
Sep-11	$69.4	$88.3	78.6%	$69.4	78.6%	($18.9)
Summary for Planning Period 2011 to 2012 through September 30, 2011						
Total	$452.5	$497.6		$452.5	90.9%	($45.2)

13 FTR Payout Ratio calculation differs from previous State of the Market reports. The updated FTR Payout Ratio includes monthly adjustments, and excludes excess revenue distributions to or from other months.

Figure 8-4 Original FTR payout ratio with adjustments by month, excluding excess revenue distribution: January 2004 to September 2011 (New Figure)

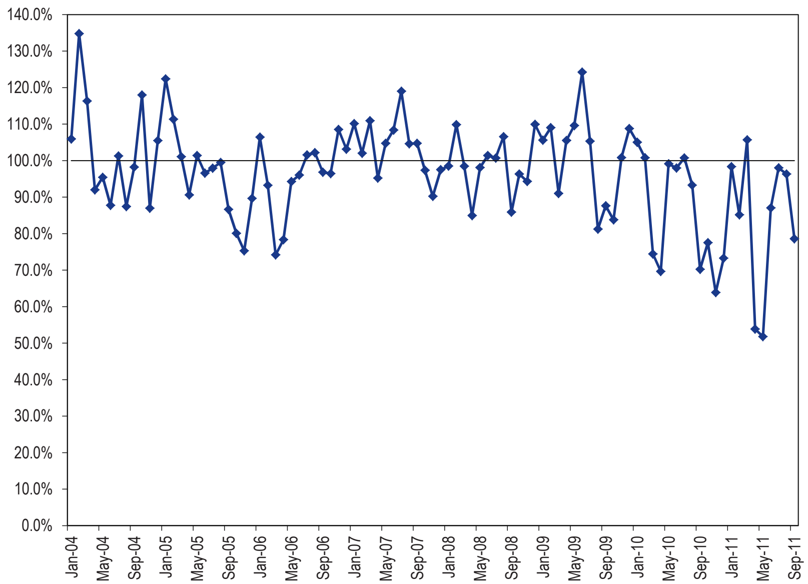


Figure 8-5 FTR payout ratio by month: June 2003 to September 2011[14] (See 2010 SOM, Figure 8-9)

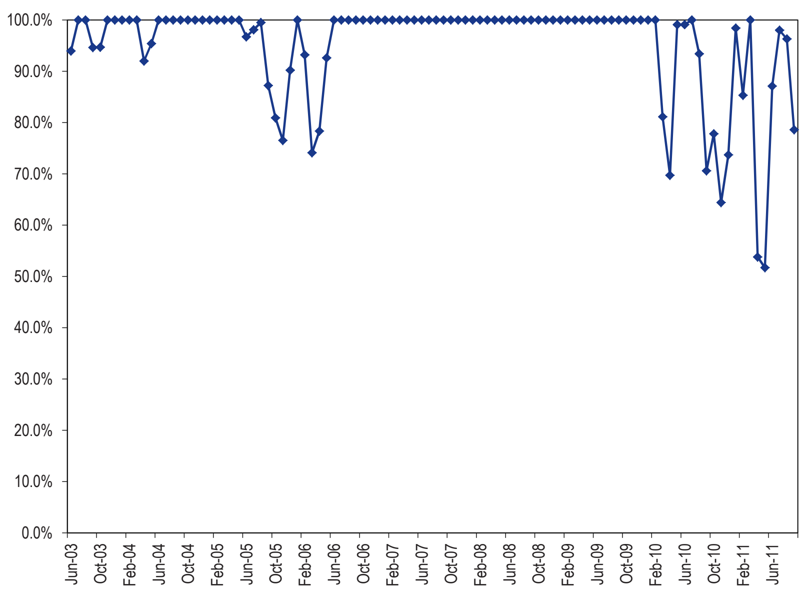
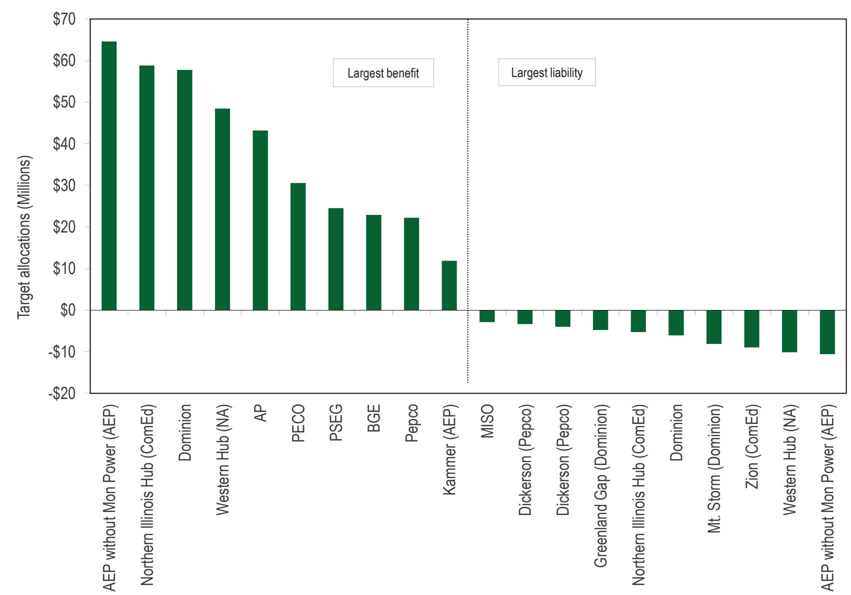


Table 8-11 FTR payout ratio by planning period (See 2010 SOM, Table 8-22)

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	84.9%
2011/2012*	90.9%

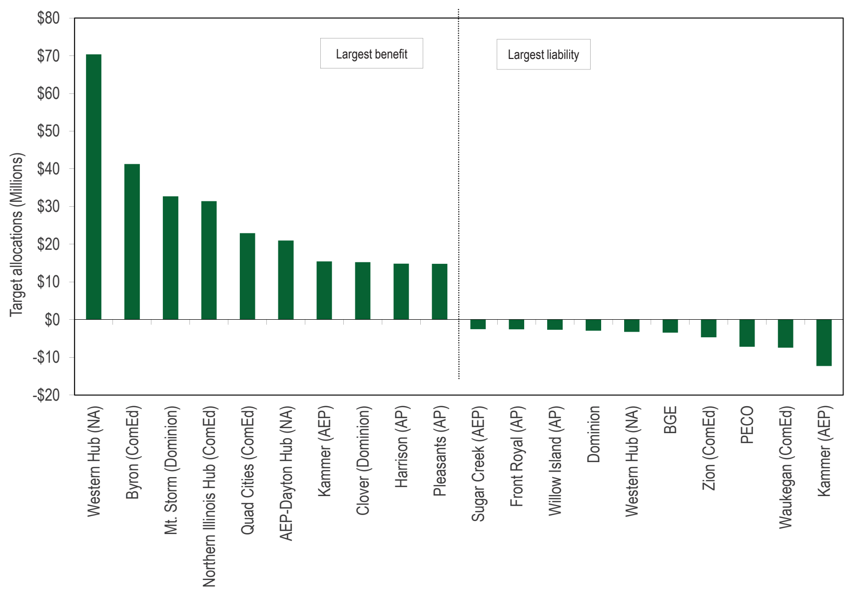
* through September 30, 2011

Figure 8-6 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2011 to 2012 through September 30, 2011 (See 2010 SOM, Figure 8-10)



14 The underlying data for Figure 8-5 and Table 8-11 is from the "FTR Credit" spreadhseet posted on PJM's website at <http://www.pjm.com/markets-and-operations/ftr/revenue-adequacy.aspx and accessed on October 11, 2011>.

Figure 8-7 Ten largest positive and negative FTR target allocations summed by source: Planning period 2011 to 2012 through September 30, 2011 (See 2010 SOM, Figure 8-11)



Profitability

Table 8-12 FTR profits by organization type and FTR direction: January through September 2011 (See 2010 SOM, Table 8-23)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	$347,542,911	$16,162,222	$363,705,133
Financial	$48,146,057	$99,094,828	$147,240,885
Total	$395,688,968	$115,257,050	$510,946,018

Table 8-13 Monthly FTR profits by organization type: January through September 2011 (See 2010 SOM, Table 8-24)

	Organization Type		
Month	Physical	Financial	Total
Jan	$136,852,655	$35,473,797	$172,326,451
Feb	$39,005,792	$6,909,551	$45,915,343
Mar	($12,240,829)	$12,388,303	$147,474
Apr	$12,840,870	$13,847,760	$26,688,630
May	$15,730,508	$9,126,571	$24,857,079
Jun	$60,815,638	$28,254,404	$89,070,042
Jul	$71,119,742	$40,050,175	$111,169,918
Aug	$15,566,385	($2,910,408)	$12,655,976
Sep	$24,014,372	$4,100,733	$28,115,105
Total	$363,705,133	$147,240,885	$510,946,018

Auction Revenue Rights

Market Structure

ARR Reassignment for Retail Load Switching

Table 8-14 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2009, through September 30, 2011 (See 2010 SOM, Table 8-28)

	ARRs Reassigned (MW)		ARR Revenue Reassigned [Dollars (Thousands)]	
Control Zone	2010/2011 (12 months)	2011/2012 (4 months)*	2010/2011 (12 months)	2011/2012 (4 months)*
AECO	887	230	$6.0	$2.5
AEP	961	1,695	$21.4	$33.3
AP	4,992	717	$481.1	$73.6
ATSI	0	2,049	$0.0	$9.4
BGE	3,359	1,225	$50.5	$22.0
ComEd	3,064	1,350	$60.2	$23.8
DAY	193	230	$0.6	$0.3
DLCO	1,834	478	$8.6	$1.6
Dominion	0	1	$0.0	$0.0
DPL	1,126	416	$10.2	$3.6
JCPL	3,490	560	$28.8	$5.2
Met-Ed	3,947	696	$51.9	$11.9
PECO	12,284	926	$89.2	$10.9
PENELEC	3,745	662	$53.5	$13.4
Pepco	2,469	859	$27.3	$8.7
PPL	5,734	1,710	$74.4	$20.0
PSEG	3,416	843	$52.8	$14.0
RECO	143	31	$0.1	$0.0
Total	51,645	14,676	$1,016.5	$254.3

* Through 30-Sep-11

Market Performance

Revenue Adequacy

Table 8-15 ARR revenue adequacy (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012 (See 2010 SOM, Table 8-30)

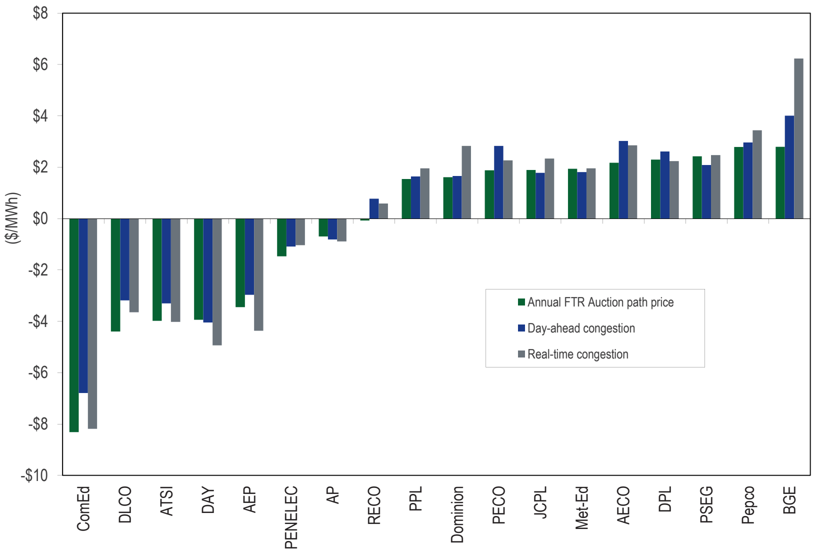
	2010/2011	2011/2012
Total FTR auction net revenue	$1,097.8	$1,082.5
Long Term FTR Auction net revenue	$23.5	$35.9
Annual FTR Auction net revenue	$1,049.8	$1,029.6
Monthly Balance of Planning Period FTR Auction net revenue*	$24.5	$17.0
ARR target allocations	$1,029.3	$982.9
ARR credits	$1,029.3	$982.9
Surplus auction revenue	$68.5	$99.6
ARR payout ratio	100%	100%
FTR payout ratio*	84.9%	90.9%

* Shows twelve months for 2010/2011 and four months ended 30-Sep-11 for 2011/2012

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

Figure 8-8 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2011 to 2012 through September 30, 2011 (See 2010 SOM, Figure 8-12)



Effectiveness of ARRs as a Hedge against Congestion

Table 8-16 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2011 to 2012 through September 30, 2011 (See 2010 SOM, Table 8-31)

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$10,192,033	$10,045	$10,202,078	$24,371,091	($14,169,014)	41.9%
AEP	$8,936,860	$55,803,819	$64,740,679	$77,631,424	($12,890,745)	83.4%
AP	$93,447,740	$22,961,350	$116,409,090	$10,350,272	$106,058,818	>100%
ATSI	$12,342,717	$37,960	$12,380,677	($26,723,682)	$39,104,359	>100%
BGE	$37,873,359	$1,281,188	$39,154,547	$20,067,359	$19,087,189	>100%
ComEd	$120,226,046	$6,225,744	$126,451,790	($118,241,494)	$244,693,284	>100%
DAY	$2,688,799	$368,070	$3,056,869	$1,851,736	$1,205,133	>100%
DLCO	$3,529,256	$15,587	$3,544,843	$1,656,061	$1,888,783	>100%
Dominion	$7,312,099	$42,861,676	$50,173,775	$11,479,723	$38,694,052	>100%
DPL	$14,213,248	$485,264	$14,698,512	$24,890,836	($10,192,324)	59.1%
JCPL	$16,099,644	$450,359	$16,550,003	$30,122,276	($13,572,273)	54.9%
Met-Ed	$13,826,662	$1,142,880	$14,969,542	$10,239,780	$4,729,762	>100%
PECO	$23,696,233	$10,565,705	$34,261,938	$15,173,391	$19,088,547	>100%
PENELEC	$21,283,357	$2,724,034	$24,007,391	$13,810,911	$10,196,480	>100%
Pepco	$44,345,533	$2,639,081	$46,984,614	$45,245,917	$1,738,698	>100%
PJM	$5,741,746	$1,102,664	$6,844,410	$10,703,990	($3,859,580)	63.9%
PPL	$22,829,320	$1,606,490	$24,435,810	$30,756,520	($6,320,710)	79.4%
PSEG	$54,249,064	$560,573	$54,809,637	$15,580,587	$39,229,049	>100%
RECO	($637,482)	$0	($637,482)	$1,388,763	($2,026,245)	0.0%
Total	$512,196,234	$150,842,489	$663,038,723	$200,355,460	$462,683,263	>100%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-17 ARR and FTR congestion hedging by control zone: Planning period 2011 to 2012 through September 30, 2011 (See 2010 SOM, Table 8-32)

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$10,219,671	$8,185,759	$17,745,681	$659,749	$17,968,632	($17,308,883)	3.7%
AEP	$172,400,543	$91,740,466	$165,311,168	$98,829,841	$90,405,544	$8,424,297	>100%
AP	$173,353,904	$38,656,615	$125,239,745	$86,770,774	$49,674,789	$37,095,985	>100%
ATSI	$12,280,544	$5,938,400	($2,885,806)	$21,104,750	($33,929,068)	$55,033,818	>100%
BGE	$41,124,662	$35,592,366	$41,569,161	$35,147,867	$30,664,198	$4,483,669	>100%
ComEd	$133,942,601	$53,174,737	$87,781,435	$99,335,903	$104,528,899	($5,192,995)	95.0%
DAY	$5,410,276	$739,617	$3,233,080	$2,916,813	$3,755,202	($838,389)	77.7%
DLCO	$3,624,433	$2,790,268	$1,804,497	$4,610,204	$4,223,681	$386,523	>100%
Dominion	$167,295,730	$54,437,033	$164,095,074	$57,637,689	$48,621,680	$9,016,008	>100%
DPL	$15,595,316	$8,151,147	$25,324,936	($1,578,473)	$15,682,702	($17,261,175)	0.0%
JCPL	$17,993,503	$10,539,282	$35,162,678	($6,629,893)	$21,681,566	($28,311,459)	0.0%
Met-Ed	$19,044,459	$7,307,533	$28,258,422	($1,906,430)	($4,040,867)	$2,134,437	0.0%
PECO	$36,549,743	$33,962,891	$35,933,726	$34,578,908	$8,658,905	$25,920,002	>100%
PENELEC	$29,176,150	$29,419,597	$81,483,032	($22,887,285)	$25,011,822	($47,899,107)	0.0%
Pepco	$52,624,626	$41,076,193	$143,371,222	($49,670,403)	$35,210,299	($84,880,702)	0.0%
PJM	$9,394,740	($1,976,290)	$2,747,504	$4,670,946	($9,315,796)	$13,986,743	>100%
PPL	$26,926,220	$14,229,429	$35,758,237	$5,397,412	($3,455,863)	$8,853,275	>100%
PSEG	$56,597,442	$20,623,828	$101,491,038	($24,269,768)	$5,881,713	($30,151,480)	0.0%
RECO	($637,482)	($1,446,674)	($10,897,967)	$8,813,811	$1,325,672	$7,488,138	>100%
Total	$982,917,081	$453,142,197	$1,082,526,863	$353,532,415	$412,553,708	($59,021,293)	85.7%

Table 8-18 ARR and FTR congestion hedging: Planning periods 2010 to 2011 and 2011 to 2012[15] (See 2010 SOM, Table 8-33)

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2010/2011	$1,030,977,744	$1,433,088,990	$1,097,817,297	$1,366,249,437	$1,409,897,924	($43,648,487)	96.9%
2011/2012*	$327,638,546	$453,142,197	$364,868,837	$415,911,906	$412,553,708	$3,358,199	>100%

* Shows four months ended 30-Sep-11

ARRs and FTRs as a Hedge against Total Real Time Energy Charges

Table 8-19 ARRs and FTRs as a hedge against energy charges by control zone: January through September 2011 (See 2010 SOM, Table 8-34)

Control Zone	ARR Related Hedge (Including Self-Scheduled FTRs)	FTR Hedge (Excluding Self-Scheduled FTRs)	Total ARR and FTR Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and FTR Credits
AECO	$6,129,521	$3,496,415	$9,625,936	$496,119,328	1.9%
AEP	$116,588,614	$46,882,407	$163,471,021	$4,354,274,786	3.8%
AP	$156,815,182	$9,785,101	$166,600,284	$1,719,418,321	9.7%
ATSI	$4,152,191	$6,454,985	$10,607,175	$1,113,964,857	1.0%
BGE	$27,639,416	$7,641,805	$35,281,221	$1,511,516,265	2.3%
ComEd	$83,742,856	$24,614,519	$108,357,374	$2,978,427,202	3.6%
DAY	$3,564,519	$504,167	$4,068,686	$559,630,656	0.7%
DLCO	$3,282,136	$3,871,995	$7,154,131	$489,068,172	1.5%
Dominion	$110,258,707	$13,245,047	$123,503,755	$3,950,313,589	3.1%
DPL	$10,454,684	($1,393,430)	$9,061,254	$811,599,331	1.1%
JCPL	$13,030,310	$11,452,594	$24,482,904	$1,049,925,982	2.3%
Met-Ed	$11,306,671	($1,335,044)	$9,971,627	$623,749,955	1.6%
PECO	$37,462,514	$19,199,090	$56,661,605	$1,753,777,192	3.2%
PENELEC	$19,625,850	$331,825	$19,957,675	$634,674,584	3.1%
Pepco	$26,374,421	($32,069,859)	($5,695,438)	$1,366,413,037	(0.4%)
PJM	$11,836,181	($1,695,362)	$10,140,819	NA	NA
PPL	$18,137,081	$17,260,718	$35,397,799	$1,666,914,774	2.1%
PSEG	$39,182,733	($2,225,614)	$36,957,120	$1,978,536,925	1.9%
RECO	($173,917)	$1,434,648	$1,260,731	$62,254,427	2.0%
Total	$699,409,670	$127,456,007	$826,865,677	$27,148,521,603	3.0%

15 The FTR credits do not include after-the-fact adjustments. For the 2011 to 2012 planning period, the ARR credits were the total credits allocated to all ARR holders for the first four months (June through September 2011) of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the first four months of this planning period and the portion of Annual FTR Auction revenue distributed during those four months.