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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 June*.

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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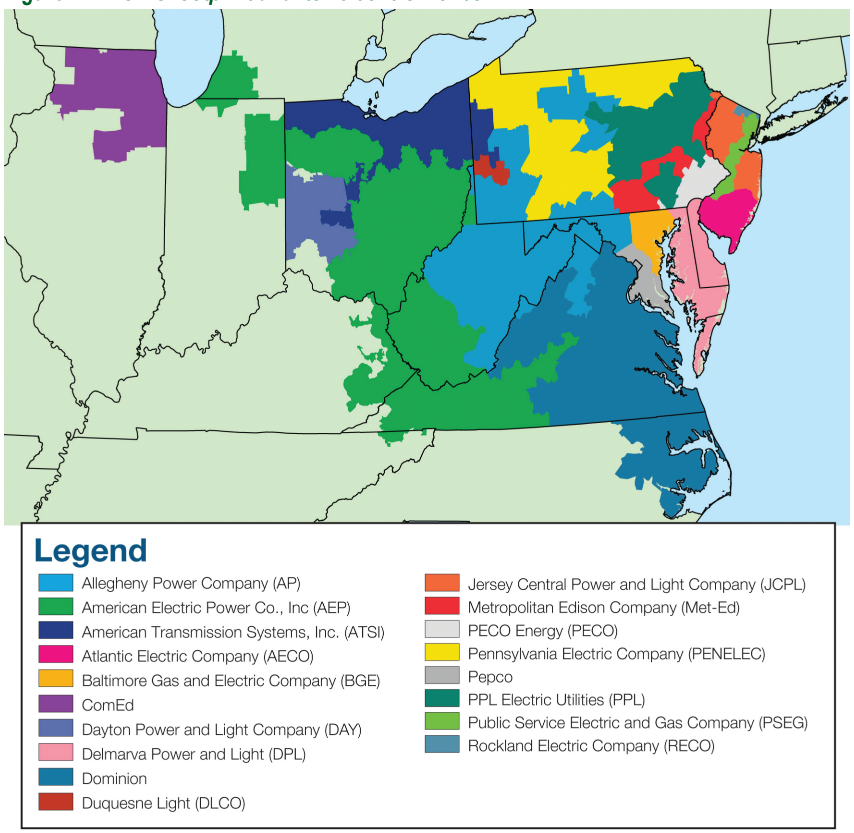
SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of June 30, 2011, had installed generating capacity of 179,813 megawatts (MW) and more than 700 market buyers, sellers and traders of electricity in a region including more than 58 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1)[1]. In the first six months of 2011, PJM had total billings of $18.7 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[2]



1 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.

2 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.[3, 4]

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 June* include the one month of ATSI zone resources' presence in the PJM markets.

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first six 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.

3 See also the *2010 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

4 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."

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.

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 six 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 six months of 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1216 with a minimum of 889 and a maximum of 1564 in the January through June 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, indicates 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.[5] 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

5 OATT Attachment M

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.[6]

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 and the submitted sell offer exceeded the defined offer cap.

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

- Market design was evaluated as mixed because while there are many positive features of the 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, a definition of DR which permits an inferior product to substitute for capacity and inadequate rules to address buyer side market power.

6 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.

Table 1-3 The Regulation Market results were not competitive[7]

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 94 percent of the hours in the first six 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 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.

7 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.
- Participant behavior was evaluated as competitive because the market rules require 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 by offer capping those suppliers.

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 five 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 six months of 2011 and there is no limit on FTR demand in any FTR auction.
- Performance was evaluated as competitive because it reflected the interaction between participant 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.[8] 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

8 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).

Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[9]

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.[10] The MMU has direct, confidential access to the FERC.[11] The MMU may also refer matters to the attention of State commissions.[12]

9 OATT Attachment M § IV; 18 CFR § 1c.2.
10 OATT Attachment M § IV.
11 OATT Attachment M § IV.K.3.
12 OATT Attachment M § IV.H.

The MMU monitors market behavior for violations of FERC Market Rules.[13] 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,[14] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[15] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[16]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[17] 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[18] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[19] 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 excercise 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

13 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.").
14 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.
15 OATT Attachment M § II(h-1).
16 OATT Attachment M § IV.C.
17 OATT Attachment M § IV.I.1.
18 *Id.*
19 *Id.*

Development Guidelines (CDG).[20] 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.[21]

The MMU also reviews operational parameter limits included with unit offers,[22] evaluates compliance with the requirement to offer into the energy and capacity markets,[23] evaluates the economic basis for unit retirement requests,[24] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[25]

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.[26] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[27] 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.[28] 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.[29] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[30]

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,"[31] 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 June*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

In addition, the MMU recommends that the Synchronized Reserve Market design, including compliance monitoring and non-compliance penalties, 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. (See Section 6, "Ancillary Services", Page 142)

Highlights

The following presents highlights of each of the sections of the *2011 Quarterly State of the Market Report for PJM: January through June*, 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 6,212, or 4.0 percent, from 156,562 MW in the second quarter of 2010 to 162,774 MW in the second quarter of 2011. The large increase in offered supply is the result of the integration of the ATSI zone. (Page 17)

- The PJM system peak load for the second quarter of 2011 was 144,350 MW, which was 18,162 MW, or 14.4 percent, higher than the peak load in the second quarter of 2010. The peak load occurred on Wednesday, June 8, 2011, HE 17. The second quarter 2011 includes the integration of the ATSI transmission zone, which accounted for 12,707 MW in the peak hour of second quarter 2011. The peak load excluding the ATSI transmission zone was 131,699 MW, occurring on June 8, 2011, HE 18. (Page 17)

- PJM average real-time load in the first six months of 2011 increased by 0.9 percent from the first six months of 2010, from 78,106 MW to 78,823 MW. PJM average day-ahead load in the first six months of 2011 decreased by 2.9 percent from the first six months of 2010, from 89,830 MW to 87,260 MW. (Page 29 and Page 30)

- PJM Real-Time Energy Market prices increased in the first six months of 2011 compared to the first six months of 2010. The load-weighted average LMP was 5.9 percent higher in the first six months of 2011

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

than in the first six months of 2010, $48.47 per MWh versus $45.75 per MWh. (Page 32 and Page 33)

- PJM Day-Ahead Energy Market prices increased in the first six months of 2011 compared to the first six months of 2010. The load-weighted LMP was 2.2 percent higher in the first six months of 2011 than in the first six months of 2010, $47.12 per MWh versus $46.12 per MWh. (Page 34 and Page 35)

- Levels of offer capping for local market power remained low. In the first six months of 2011, 0.7 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. (Page 19)

- The overcollected portion of transmission losses decreased in the first six months of 2011 to $308.4 million or 44.0 percent of the total losses compared to $377.5 million or 50.3 percent of total losses in the same period in 2010. (Page 43)

- In the first six months of 2011, the total MWh of load reduction under the Economic Program decreased by 16,377 MWh compared to the same period in 2010, from 20,225 MWh in 2010 to 3,848 MWh in 2011, an 81 percent decrease. Total payments under the Economic Program decreased by $476,431, from $761,854 in 2010 to $285,423 in 2010, a 63 percent decrease. (Page 56)

- In the first six months of 2011, total capacity payments under the Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, increased by $61 million, or 29 percent, compared to the same period in 2010, from $215 Million in 2010 to $276 Million in 2011. (Page 60)

Section 3, Energy Market, Part 2

- Operating reserve charges increased $24,826,194, or 10.1 percent, to $270,734,409 in the first six months of 2011, from $245,908,215 in the first six months of 2010. Reliability credits decreased $9,827,203, or 18.2 percent, in the first six months of 2011 compared to the first six months of 2010, and deviation credits increased $10,216,220, or 11.8 percent. (Page 77)

- Reliability charges were $44,230,427, 31.3 percent of all balancing operating reserve charges for the first six months of 2011, and deviation charges were $97,092,749, or 68.7 percent. (Page 78)

- The Western reliability rate in the first six months of 2011 is the highest balancing operating reserve rate, averaging $0.9802/MWh. The average daily RTO deviation rate of $0.1619/MWh decreased in the first six months of 2011 when compared to the rate of $0.7360/MWh in the first six months of 2010. (Page 80)

- Operating reserve credits for dispatchable transactions, which are a subset of pool-scheduled spot market import transactions, or balancing transaction operating reserve credits, for the months January through June 2011, were $1,252,846. The year with the next highest first half total balancing transaction operating reserve credits was in 2008, when credits were $818,778. (Page 98)

- 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 34.3 percent of total operating reserve credits in the first six months of 2011, compared to 42.3 percent in the first six months of 2010. In the first six months of 2011, the top generation owner received 30.9 percent of the total operating reserve credits paid. (Page 87)

- The regional concentration of balancing operating reserves for the first six months of 2011 is slightly lower than the first six months of 2010, with 31.1 percent of the credits being paid to units operating in the PSEG zone, 24.7 percent in the Dominion zone, and 11.2 percent in the AEP zone. (Page 86)

- In the first six months of 2011, coal units provided 47.6 percent, nuclear units 34.8 percent and gas units 12.8 percent of total generation. Compared to the first six months of 2010, generation from coal units decreased 5.6 percent, and generation from nuclear units decreased 1.6 percent. Generation from natural gas units increased 42.4 percent, and generation from oil units increased 1.8 percent. (Page 64)

- At the end of June 2011, 80,787 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 167,000 MW in 2011. Wind projects account for approximately 39,656 MW of capacity, 49.1 percent of the capacity in the queues and combined-cycle projects account for 20,304 MW, 25.1 percent, of the capacity in the queues. (Page 65)

- Three large plants (over 550 MW) have started generating in PJM since January 1, 2011. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 3,409 MW of nameplate capacity has been added in PJM in 2011 (excluding the ATSI zone additions), the most since 2003. (Page 65)

Section 4, Interchange Transactions

- On June 1, 2011 at 0100, American Transmission Systems, Inc. (ATSI) integrated into PJM. The affect of this integration on interchange transactions was the elimination of the First Energy (FE) Interface as well as the elimination of the MICHFE Interface Pricing Point. (Page 91)

- Real-time net exports decreased to -2949.1 GWh during the first six months of 2011 from -3,356.4 GWh during the first six months of 2010. During the first six months of 2011, there were day-ahead net imports of 10,914.7 GWh compared to net exports of -5,489.5 GWh during the first six months of 2010. (Page 101 and Page 102)

- 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 in 59 percent of hours between PJM and MISO and in 47 percent of hours between PJM and NYISO during the first six months of 2011. (Page 98)

- During the first six months of 2011, net scheduled interchange was -1,623 GWh and net actual interchange was -1,876 GWh for a difference of 253 GWh or 15.6 percent (7.7 percent during the first six months of 2010 and 5.2 percent for the calendar year 2010). This difference is system inadvertent. (Page 109)

- PJM initiated fewer TLRs during the first six months of 2011 than during the first six months of 2010 (40 TLRs during the first six months of 2011 compared to 58 TLRs during the first six months of 2010). (Page 96)

- 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 1,634 bids per day for the period between September 17, 2010 through June 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. (Page 96)

- Total uncollected congestion charges during the first six months of 2011 were $10,790, compared to $1.2 million for the first six 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. (Page 97)

- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were $1.3 million during the first six months of 2011, an increase from $290,515 in the first six months of 2010. (Page 98)

Section 5, Capacity Markets

- The 2014/2015 Base Residual Auction was run in the second quarter of 2011. The RTO annual resource clearing price in the 2014/2015 RPM Base Residual Auction was $125.99 per MW-day, an increase of $98.26 per MW-day from the 2013/2014 RPM Base Residual Auction resource clearing price. (Page 128)

- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2014/2015 delivery year. (Page 122)

- Capacity in the RPM load management programs totals 9,681.0 MW for June 1, 2011. (Page 123 and Page 124)

- 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 $127.46 per MW-day in 2014. (Page 127)

- Average PJM equivalent demand forced outage rate (EFORd) increased from 7.8 percent in the first six months of 2010 to 7.9 percent in the first six months of 2011. (Page 131)

- The PJM aggregate equivalent availability factor (EAF) decreased from 84.3 percent in the first six months of 2010 to 82.2 percent in the first six months of 2011. The equivalent maintenance outage factor (EMOF) increased from 2.7 percent in the first six months of 2010 to 3.1 percent in the first six months of 2011, the equivalent planned outage factor (EPOF) increased from 8.4 percent from the first six months of 2010 to 9.7 percent in the first six months of 2011, and the equivalent forced outage factor (EFOF) increased from 4.6 percent in the first six months of 2010 to 5.0 percent in the first six months of 2011. (Page 130)

Section 6, Ancillary Services

- The load weighted regulation market clearing price for the first six months of 2011 was $15.53, 13 percent lower than the $17.76 price for the first six months of 2010. Regulation total costs per MW for the first six months of 2011 were $30.89, an increase of 3 percent from the $30.05 total cost in the first six months of 2010. For the first six months of 2011 the total cost of regulation per MW was 101 percent higher than the market clearing price. For the first six months of 2010 the total cost of regulation was 67 percent higher than the market clearing price. (Page 140)

  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 at the direction of PJM Dispatch as a result of binding constraints or performance problems.

- Total self-scheduled regulation MW in the first six months of 2011 was 16 percent of all regulation, a decrease from 20 percent in the first six months of 2010. (Page 147)

- Of the LSEs' obligation to provide regulation during the first six months of 2011, 81 percent was purchased in the spot market, 16 percent was self scheduled, and three percent was purchased bilaterally. (Page 147)

- The load weighted synchronized reserve market price in the first six months of 2011 was $12.18 per MWh, $3.26 higher than the price during the first six months of 2010. The total cost of synchronized reserves per MWh during the first six months of 2011 was $15.72, a 30 percent increase over the cost of synchronized reserves ($12.13) during the same period of 2010. The cost to price ratio of synchronized reserve during the first six months of 2011 was 129 percent, a decrease from the cost to price ratio of 136 percent in the first six months of 2010. (Page 155)

  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.

- In December of 2010, PJM Market Operations changed the Tier 1 synchronized reserve transfer capacity across the AP South interface from 15 percent of available Tier 1 to five percent.[32] 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 April 2011. In May, 2011, the implementation of the new TrAIL line made Bedington – Black Oak the most restrictive constraint rather than AP South. This allowed more Tier 1 to become available. PJM increased the reserve transfer capacity several times to its current 30 percent. As a result the amount of Tier 2 required dropped in May and significantly in June. (Page 140)

- The load weighted price of DASR in the first six months of 2011 was $0.44 per MW. In the first six months of 2010, the load weighted price of DASR was $0.06 per MW. The increase in average DASR price was caused by several days of high DASR prices in early June, which were primarily the result of opportunity costs, which were a function of high LMPs. (Page 143)

- Black start zonal charges in the first six months of 2011 ranged from $0.02 per MW in the Pepco zone to $0.66 per MW in the PPL zone. (Page 156)

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

Section 7, Congestion

- Congestion costs in the first six months of 2011 decreased by 13 percent over congestion costs in the first six months of 2010. (Page 160)

- Net balancing congestion costs were -$132.6 million in the first six months of 2011 and -$89.4 million in the first six months of 2010. Negative balancing congestion costs indicates that the congestion payments in the Day-Ahead market exceeded congestion payments in the Real-Time market. (Page 162)

- In the first six months of 2011, ComEd was the most congested zone. ComEd accounted for nearly 21 percent of the total congestion cost (Table 7-21). In the first six months of 2010, Dominion was the most congested zone, accounting for nearly 20 percent of the total congestion cost. (Page 174)

- May and June congestion costs were significantly lower compared to 2010 (48.2 percent and 33.2 percent). March congestion costs were substantially higher compared to 2010 (120.8 percent). (Page 161)

- PJM backbone projects are a subset of significant baseline 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 February 28, 2011, PJM announced that the Board has decided to hold the Potomac – Appalachian Transmission Highline (PATH) project in abeyance in its 2011 Regional Transmission Expansion Plan (RTEP), but did not direct the sponsoring Transmission Owners to cancel or abandon the PATH project.

  On February 28, 2011, American Electric Power and FirstEnergy Corp., the sponsoring Transmission Owners, announced that they would file to withdraw their applications for state regulatory approval of the PATH. (Page 159)

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.

- FTRs were paid at 84.9 percent of the target allocation level for the full 2010 to 2011 planning period and 86.9 percent for the first month of the 2011 to 2012 planning period. (Page 228)

- Total FTR buy bids in the Annual FTR Auction for the 2011 to 2012 planning period increased 88 percent from 1,708,556 MW during the prior planning period to 3,214,678 MW. The Annual FTR Auction for the 2011 to 2012 planning period cleared 341,726 MW, an increase of 48 percent from 231,663 MW during the prior planning period. (Page 217)

- The Annual FTR Auction generated $1,029.6 million of net revenue for all FTRs during the 2011 to 2012 planning period, a decrease of $20.2 million from $1,049.8 million for the 2010 to 2011 planning period. (Page 223)

- In the 2011 to 2012 planning period, 102,476 MW of ARR requests were allocated, compared to 101,843 MW for the 2010 to 2011 planning period. (Page 232)

- Network Service Users and Firm Transmission Customers in the ATSI Control Zone chose to directly allocate 4,189 MW, or 60 percent, of ARRs to FTRs. (Page 232)

- In the 2011 to 2012 planning period, 44.4 percent of ARRs were self-scheduled as FTRs, a 10.2 percentage point decrease from the prior planning period. (Page 218)

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 June 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 96.3 percent of the total price per MWh in the first six months of 2011. The cost of energy was 70.9 percent of the total price per MWh in 2011, the cost of capacity was 18.9 percent and the cost of transmission service was 6.5 percent in the first six months of 2011.

The total per MWh price of wholesale power for the first six months of 2011, $68.39, was 7.6 percent higher than total per MWh price of wholesale power for the first six months of 2010, $63.59. This increase in the total price per MWh is largely attributable to the 10.7 percent increase in the price of capacity and the 11.4 percent increase in the price of transmission.

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.[33]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[34]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[35]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[36]
- 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.[37]
- 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.[38]
- 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.[39]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[40]
- The Black Start component is the average cost per MWh of black start service.[41]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[42]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[43]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[44]

33 OATT §§ 13.7, 14.5, 27A & 34.
34 OA Schedules 1 §§ 3.2.3 & 3.3.3.
35 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
36 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
37 OATT Schedule 12.
38 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
39 OATT Schedule 1A.
40 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6..
41 OATT Schedule 6A.
42 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
43 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
44 OA Schedule 1 § 3.6.

- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[45]

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

Category	Totals ($ Millions) Jan-Jun 2010	Totals ($ Millions) Jan-Jun 2011	Percent Change Totals	Jan-Jun 2010 $/MWh	Jan-Jun 2011 $/MWh	Percent Change $/MWh	Jan-Jun 2010 Percent	Jan-Jun 2011 Percent	Percent Change in Proportions
Load Weighted Energy	$15,518.26	$16,592.33	6.9%	$45.75	$48.47	5.9%	71.9%	70.9%	(1.5%)
Capacity	$3,966.86	$4,433.24	11.8%	$11.69	$12.95	10.7%	18.4%	18.9%	3.0%
Transmission Service Charges	$1,359.44	$1,527.78	12.4%	$4.01	$4.46	11.4%	6.3%	6.5%	3.5%
Operating Reserves (Uplift)	$237.20	$274.89	15.9%	$0.72	$0.80	11.6%	1.1%	1.2%	6.8%
Reactive	$124.67	$139.09	11.6%	$0.37	$0.41	10.6%	0.6%	0.6%	2.8%
PJM Administrative Fees	$125.33	$128.97	2.9%	$0.37	$0.38	2.0%	0.6%	0.6%	(5.2%)
Regulation	$116.30	$114.17	(1.8%)	$0.34	$0.33	(2.7%)	0.5%	0.5%	(9.6%)
Transmission Enhancement Cost Recovery	$48.88	$103.87	112.5%	$0.14	$0.30	110.6%	0.2%	0.4%	95.8%
Synchronized Reserves	$18.87	$36.53	93.6%	$0.06	$0.11	91.8%	0.1%	0.2%	78.3%
Transmssion Owner (Schedule 1A)	$29.01	$31.44	8.4%	$0.09	$0.09	7.4%	0.1%	0.1%	(0.2%)
Day Ahead Scheduling Reserve (DASR)	$6.99	$10.81	54.7%	$0.02	$0.03	53.3%	0.0%	0.0%	42.5%
NERC/RFC	$6.83	$6.51	(4.8%)	$0.02	$0.02	(5.6%)	0.0%	0.0%	(12.3%)
Black Start	$5.36	$6.44	20.3%	$0.02	$0.02	19.2%	0.0%	0.0%	10.8%
RTO startup and Expansion	$4.55	$4.55	0.1%	$0.01	$0.01	(0.9%)	0.0%	0.0%	(7.8%)
Load Response	$2.13	$1.88	(11.9%)	$0.01	$0.01	(12.7%)	0.0%	0.0%	(18.8%)
Transmission Facility Charges	$0.67	$0.73	8.8%	$0.00	$0.00	7.9%	0.0%	0.0%	0.3%
Total	$21,571.34	$23,413.23	8.5%	$63.59	$68.39	7.6%	100.0%	100.0%	0.0%

45 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 June 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 six 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 six months of 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1216 with a minimum of 889 and a maximum of 1564 in the January through June 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 6,212, or 4.0 percent, from 156,562 MW in the second quarter of 2010 to 162,774 MW in the second quarter of 2011. The large increase in offered supply is the result of the integration of the ATSI zone.

- The PJM system peak load for the second quarter of 2011 was 144,350 MW, which was 18,162 MW, or 14.4 percent, higher than the peak load in the second quarter of 2010. The peak load occurred on Wednesday, June 8, 2011, HE 17. The second quarter 2011 includes the integration of the ATSI transmission zone, which accounted for 12,707 MW in the peak hour of second quarter 2011. The peak load excluding the ATSI transmission zone was 131,699 MW, occurring on June 8, 2011, HE 18.

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.

- PJM average real-time load in the first six months of 2011 increased by 0.9 percent from the first six months of 2010, from 78,106 MW to 78,823 MW. PJM average day-ahead load in the first six months of 2011 decreased by 2.9 percent from the first six months of 2010, from 89,830 MW to 87,260 MW.

- PJM Real-Time Energy Market prices increased in the first six months of 2011 compared to the first six months of 2010. The load-weighted average LMP was 5.9 percent higher in the first six months of 2011 than in the first six months of 2010, $48.47 per MWh versus $45.75 per MWh.

- PJM Day-Ahead Energy Market prices increased in the first six months of 2011 compared to the first six months of 2010. The load-weighted LMP was 2.2 percent higher in the first six months of 2011 than in the first six months of 2010, $47.12 per MWh versus $46.12 per MWh.

- Levels of offer capping for local market power remained low. In the first six months of 2011, 0.7 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.

- The overcollected portion of transmission losses decreased in the first six months of 2011 to $308.4 million or 44.0 percent of the total losses compared to $377.5 million or 50.3 percent of total losses in the same period in 2010.

- In the first six months of 2011, the total MWh of load reduction under the Economic Program decreased by 16,377 MWh compared to the same period in 2010, from 20,225 MWh in 2010 to 3,848 MWh in 2011, an 81 percent decrease. Total payments under the Economic Program decreased by $476,431, from $761,854 in 2010 to $285,423 in 2010, a 63 percent decrease.

- In the first six months of 2011, total capacity payments under the Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, increased by $61 million, or 29 percent, compared to the same period in 2010, from $215 Million in 2010 to $276 Million in 2011.

Recommendations

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

Overview

Market Structure

- **Supply.** During the second quarter of 2011, the PJM Energy Market received an hourly average of 162,774 MWh in day-ahead supply offers including hydroelectric generation, 6,212 MWh higher than the second quarter of 2010 average daily offered supply of 156,562 MWh.[4]

- **Demand.** The PJM system peak load for the second quarter of 2011 was 144,350 MW in the hour ended 1700 EPT on June 8, 2011, which was 18,162 MW, or 14.4 percent, higher than the PJM peak load for the second quarter of 2010, which was 126,189 MW in the hour ended 1700 EPT on June 23, 2010.[5] The peak load excluding the ATSI transmission zone was 131,699 MW, occurring on June 8, 2011 in the hour ended 1800 EPT.

- **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.** A noncompetitive local market structure is the trigger for offer capping. PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three

4 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.

5 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).

pivotal supplier test (TPS)) as the trigger for offer capping in the first six 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 six months of 2011. In the Real-Time Energy Market offer-capped unit hours decreased from 1.2 percent in 2010 to 0.7 percent in the first six months of 2011.

- **Local Market Structure.** In the first six months of 2011, the AECO, AEP, AP, BGE, ComEd, Dominion, PECO, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.[6]

Market Performance: Load and Locational Marginal Price

- **Load.** On average, PJM real-time load increased in the first six months of 2011 by 0.9 percent from the first six months of 2010, from 78,106 MW to 78,823 MW. PJM day-ahead load decreased in the first six months of 2011 by 2.9 percent from the first six months of 2010, from 89,830 MW to 87,260 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 generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion.

  PJM Real-Time Energy Market prices increased in the first six months of 2011 compared to the first six months of 2010. The system simple average LMP was 5.2 percent higher in the first six months of 2011 than in the first six months of 2010, $45.51 per MWh versus $43.27 per MWh. The load-weighted LMP was 5.9 percent higher in the first six months of 2011 than in the first six months of 2010, $48.47 per MWh versus $45.75 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first six months of 2011 compared to the first six months of 2010. The system simple average LMP was 2.1 percent higher in the first six months of 2011 than in the first six months of 2010, $44.75 per MWh versus $43.81 per MWh. The load-weighted LMP was 2.2 percent higher in the first six months of 2011 than in the first six months of 2010, $47.12 per MWh versus $46.12 per MWh.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first six months of 2011, 10.5 percent of real-time load was supplied by bilateral contracts, 27.1 percent by spot market purchases and 62.5 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased by 1.3 percentage points; reliance on spot supply increased by 6.9 percentage points; and reliance on self-supply decreased by 5.5 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.

6 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.

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 six months of 2011, in the Economic Program, participation decreased compared to the same period in 2010. 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 calendar year 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 June 2011 (June 8, 2011), there were 1,985.1 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 assessed compliance on a zonal basis, is a broader issue that needs to be addressed. More precise locational deployment of Load Management improves efficiency while reducing the ability of a CSP to aggregate customers. 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).

  Since the implementation of the RPM design on June 1, 2007, capacity revenue has become the primary source of revenue to participants in PJM demand side programs. In the first six months of 2011, Economic Program revenues decreased by $476,431 or 63 percent compared to the same period in 2010, from $761,854 to $285,423 while Load Management (LM) Program revenues increased by $61 million or 29 percent, from $215 million to $276 million. Through the first six months of 2011, Synchronized Reserve credits increased by $2.0 million compared to the same period in 2010, from $2.4 million in 2010 to $4.4 million in 2011.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first six 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 6,212 MWh in the second quarter of 2011 compared to the second quarter of 2010, while aggregate peak load increased by 18,162 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. In real-time market, average load in the first six months of 2011 increased from the same period in 2010, from 78,106 MW to 78,823 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 six 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.[7]

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

Market Structure

Supply

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

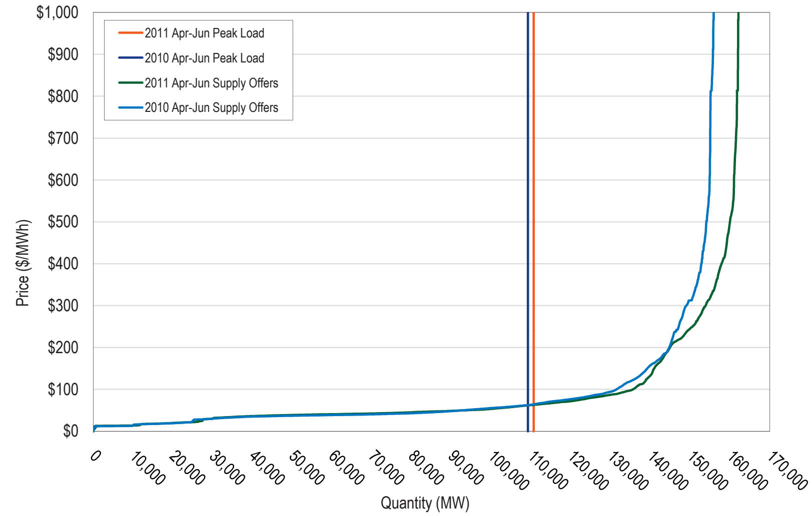


Table 2-2 Frequency distribution of unit offer prices: April through June 2011 (See 2010 SOM, Table 2-3)

Range	All Offers	PJM Dispatched Share of All Offers	Self-Scheduled Share of All Offers
($200) - $0	11.4%	26.2%	73.8%
$0 - $200	50.0%	89.0%	11.0%
$200 - $400	23.6%	95.0%	5.0%
$400 - $600	9.4%	98.9%	1.1%
$600 - $800	3.5%	97.4%	2.6%
$800 - $1,000	2.1%	84.5%	15.5%

7 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.

Demand

Table 2-3 Actual PJM footprint peak loads: April through June of 2003 to 2011 (See 2010 SOM, Table 2-4)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2011	Wed, June 08	17	144,350	NA	NA
2010	Wed, June 23	17	126,188	(18,162)	(12.6%)
2009	Thu, June 25	17	116,751	(9,438)	(7.5%)
2008	Mon, June 09	17	130,100	13,349	11.4%
2007	Wed, June 27	16	130,971	871	0.7%
2006	Tue, May 30	17	121,165	(9,806)	(7.5%)
2005	Tue, June 28	16	124,052	2,887	2.4%
2004	Wed, June 09	17	77,676	(46,375)	(37.4%)
2003	Thu, June 26	17	61,310	(16,366)	(21.1%)
2002	Wed, June 26	15	60,176	(1,134)	(1.8%)

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

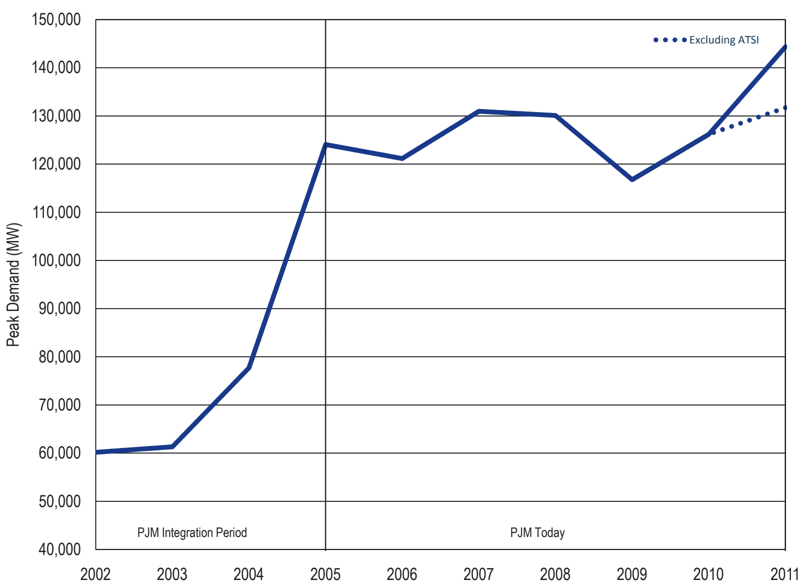
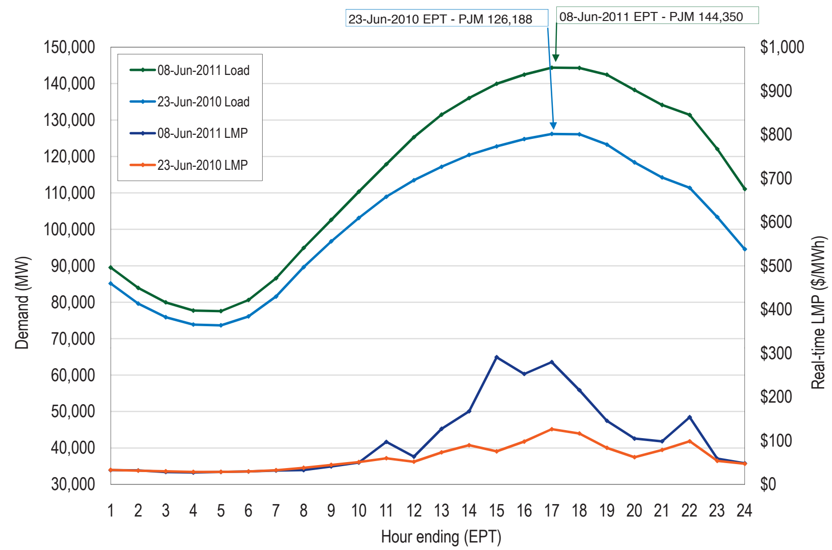


Figure 2-3 PJM second quarter peak-load comparison: Wednesday, June 8, 2011, and Wednesday, June 23, 2010 (See 2010 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

Table 2-4 PJM hourly Energy Market HHI: January through June 2011[8] (See 2010 SOM, Table 2-5)

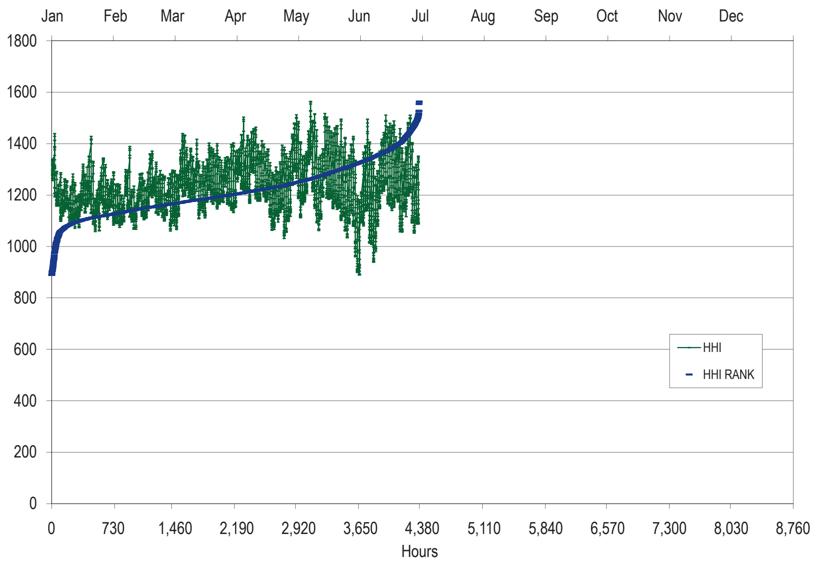
	Hourly Market HHI
Average	1216
Minimum	889
Maximum	1564
Highest market share (One hour)	30%
Highest market share (All hours)	20%
# Hours	4,343
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

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

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

	Minimum	Average	Maximum
Base	1058	1248	1546
Intermediate	765	2371	9809
Peak	649	6027	10000

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



Local Market Structure and Offer Capping

Table 2-6 Annual offer-capping statistics: Calendar years 2007 through June 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 - Jun)	0.7%	0.3%	0.0%	0.0%

Table 2-7 Real-time offer-capped unit statistics: January through June 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	0	0	11
80% and < 90%	0	0	1	0	1	17
75% and < 80%	0	0	0	0	0	7
70% and < 75%	0	0	0	0	0	6
60% and < 70%	0	0	0	0	0	20
50% and < 60%	0	0	0	0	0	22
25% and < 50%	1	1	0	0	2	87
10% and < 25%	1	2	1	1	0	36

Local Market Structure

Table 2-8 Three pivotal supplier results summary for regional constraints: January through June 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	4,912	851	17%	4,597	94%
	Off Peak	2,175	282	13%	2,054	94%
AEP-DOM	Peak	657	6	1%	657	100%
	Off Peak	1,914	32	2%	1,905	100%
AP South	Peak	13,172	194	1%	13,101	99%
	Off Peak	9,391	201	2%	9,325	99%
Bedington - Black Oak	Peak	4	0	0%	4	100%
	Off Peak	NA	NA	NA	NA	NA
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	160	87	54%	110	69%
	Off Peak	15	5	33%	14	93%

Table 2-9 Three pivotal supplier test details for regional constraints: January through June 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	304	1,781	15	2	13
	Off Peak	300	1,922	14	1	12
AEP-DOM	Peak	340	883	8	0	8
	Off Peak	367	1,298	8	0	8
AP South	Peak	403	1,089	8	0	8
	Off Peak	464	1,278	8	0	8
Bedington - Black Oak	Peak	64	536	10	0	10
	Off Peak	NA	NA	NA	NA	NA
Dominion East	Peak	115	184	1	0	1
	Off Peak	80	185	2	0	2
East	Peak	637	4,408	16	5	11
	Off Peak	327	3,323	12	5	7
West	Peak	483	3,615	15	7	7
	Off Peak	251	3,260	13	3	10

Table 2-10 Summary of three pivotal supplier tests applied to uncommitted units for regional constraints: January through June 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	4,912	191	4%	84	2%	44%
	Off Peak	2,175	81	4%	24	1%	30%
AEP-DOM	Peak	657	16	2%	10	2%	63%
	Off Peak	1,914	39	2%	24	1%	62%
AP South	Peak	13,172	126	1%	33	0%	26%
	Off Peak	9,391	166	2%	31	0%	19%
Bedington - Black Oak	Peak	4	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Dominion East	Peak	1,479	6	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	160	3	2%	0	0%	0%
	Off Peak	15	0	0%	0	0%	0%

Frequently Mitigated Unit and Associated Unit Adders

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

	FMUs and AUs			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any 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

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

Months Adder-Eligible	FMU & AU Count
1	3
2	2
3	2
4	1
5	17
6	123
Total	148

Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

Figure 2-5 PJM real-time load duration curves: January through June 2007 through 2011 (See 2010 SOM, Figure 2-5)

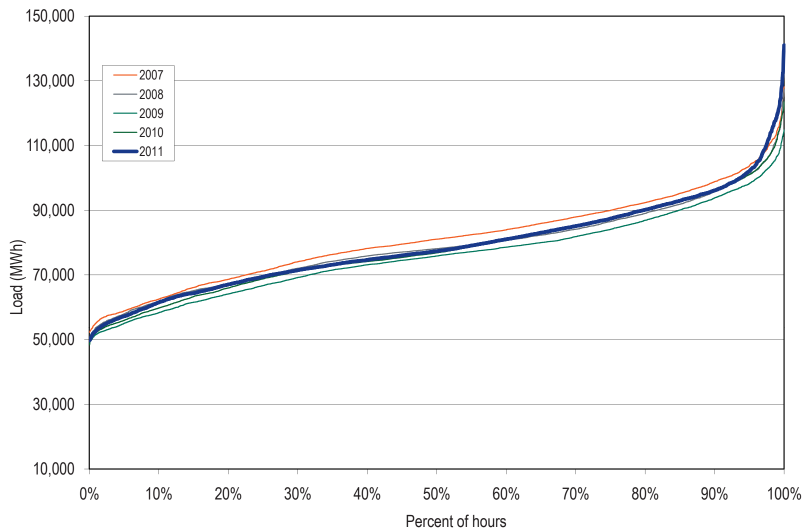
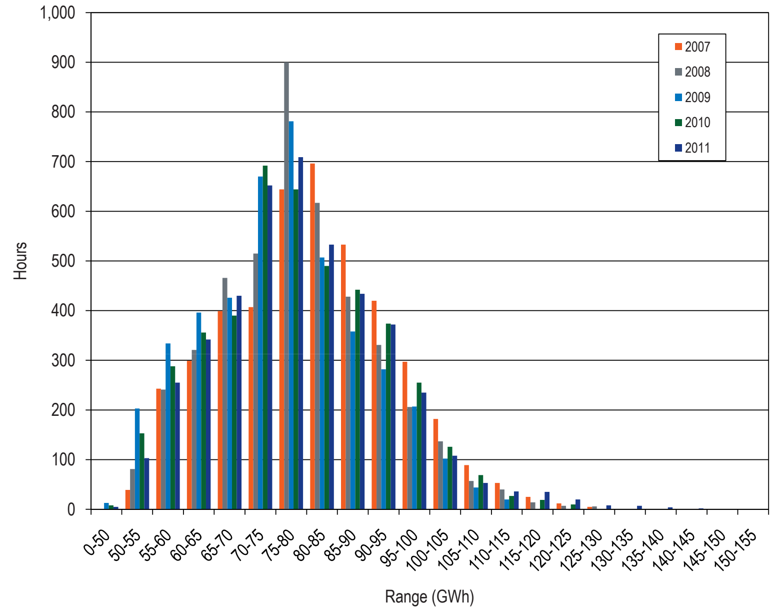


Figure 2-6 PJM real-time load histogram: January through June 2007 through 2011 (New Figure)



PJM Real-Time, Annual Average Load

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

	PJM Real-Time Load (MWh)			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	27,662	27,915	4,703	NA	NA	NA
1999	28,714	28,903	5,113	3.8%	3.5%	8.7%
2000	29,649	29,802	5,382	3.3%	3.1%	5.3%
2001	30,180	30,290	5,274	1.8%	1.6%	(2.0%)
2002	32,582	31,965	6,506	8.0%	5.5%	23.4%
2003	36,727	36,701	6,428	12.7%	14.8%	(1.2%)
2004	41,787	40,275	8,999	13.8%	9.7%	40.0%
2005	71,939	70,465	13,603	72.2%	75.0%	51.2%
2006	77,232	77,499	12,003	7.4%	10.0%	(11.8%)
2007	81,110	81,045	13,499	5.0%	4.6%	12.5%
2008	78,685	78,107	12,819	(3.0%)	(3.6%)	(5.0%)
2009	75,993	75,847	12,898	(3.4%)	(2.9%)	0.6%
2010	78,106	76,831	13,643	2.8%	1.3%	5.8%
2011	78,823	77,321	13,931	0.9%	0.6%	2.1%

PJM Real-Time, Monthly Average Load

Figure 2-7 PJM real-time average hourly load: Calendar years 2010 through June 2011 (See 2010 SOM, Figure 2-6)

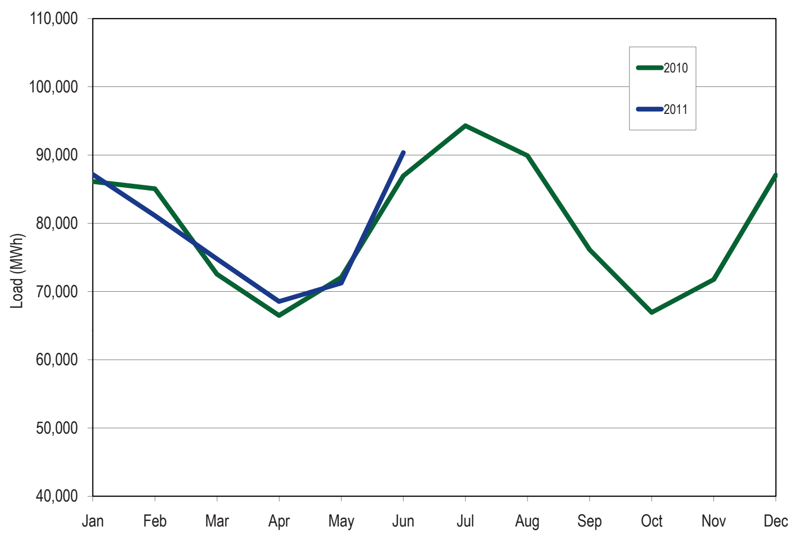


Table 2-14 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through June 2011 (See 2010 SOM, Table 2-30)

	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 (Jan - Jun)	74.63	25.20	53.84

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-8 PJM day-ahead load duration curves: January through June 2007 through 2011 (See 2010 SOM, Figure 2-7)

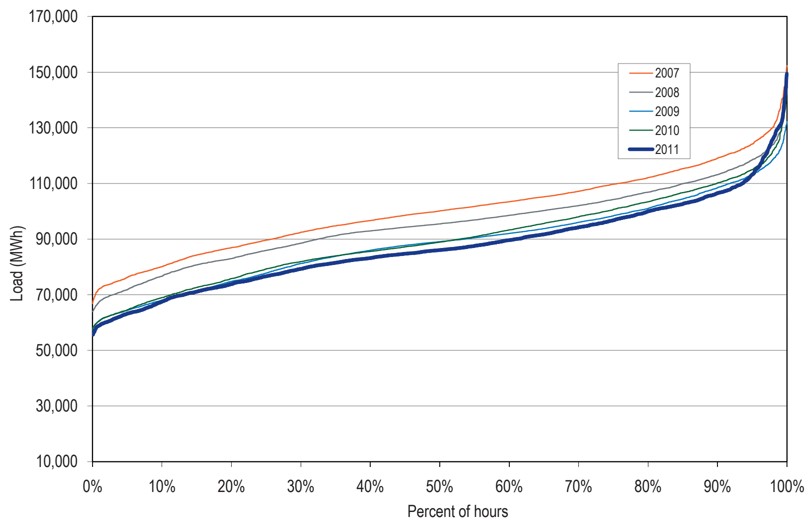
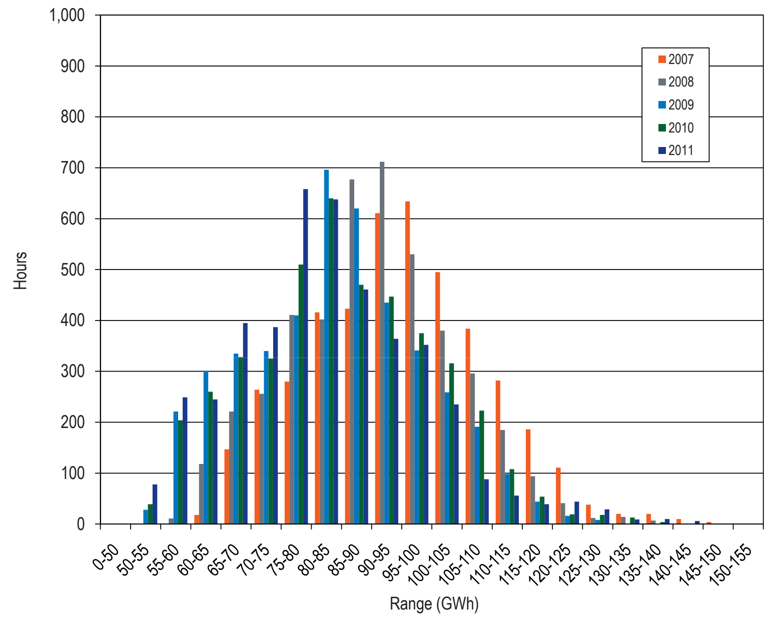


Figure 2-9 PJM day-ahead load histogram: January through June 2007 through 2011 (New Figure)



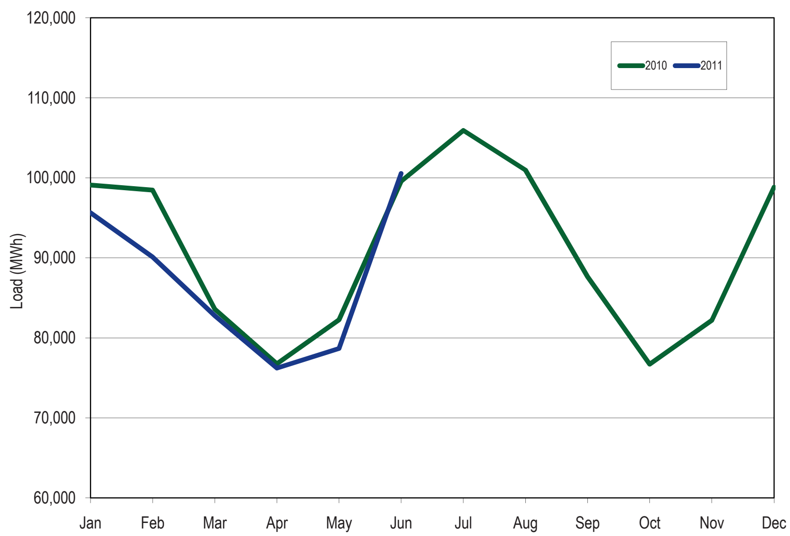
PJM Day-Ahead, Annual Average Load

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

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	35,448	36,822	8,138	NA	NA	NA
2001	32,443	31,916	5,938	(8.5%)	(13.3%)	(27.0%)
2002	37,497	36,362	8,268	15.6%	13.9%	39.2%
2003	44,112	44,378	7,730	17.6%	22.0%	(6.5%)
2004	49,393	47,476	10,003	12.0%	7.0%	29.4%
2005	85,784	84,465	14,632	73.7%	77.9%	46.3%
2006	91,060	90,850	12,862	6.1%	7.6%	(12.1%)
2007	100,097	100,118	14,532	9.9%	10.2%	13.0%
2008	95,486	95,444	13,724	(4.6%)	(4.7%)	(5.6%)
2009	88,688	89,066	14,650	(7.1%)	(6.7%)	6.7%
2010	89,830	88,894	15,372	1.3%	(0.2%)	4.9%
2011	87,260	86,041	15,402	(2.9%)	(3.2%)	0.2%

PJM Day-Ahead, Monthly Average Load

Figure 2-10 PJM day-ahead average load: Calendar years 2010 through June 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 June 2011 (See 2010 SOM, Table 2-32)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bid
Average	75,532	816	10,913	87,260	78,823	8,437	(2,476)
Median	74,208	794	10,675	86,041	77,321	8,720	(1,955)
Standard deviation	13,371	186	2,349	15,402	13,931	1,471	(877)
Peak average	83,290	897	12,465	96,652	86,848	9,804	(2,661)
Peak median	80,961	879	12,204	94,080	84,494	9,585	(2,619)
Peak standard deviation	11,775	183	1,960	13,102	12,279	823	(1,137)
Off peak average	68,608	744	9,527	78,879	71,662	7,217	(2,310)
Off peak median	67,494	721	9,391	77,512	70,488	7,024	(2,367)
Off peak standard deviation	10,630	158	1,715	12,117	11,135	982	(733)

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

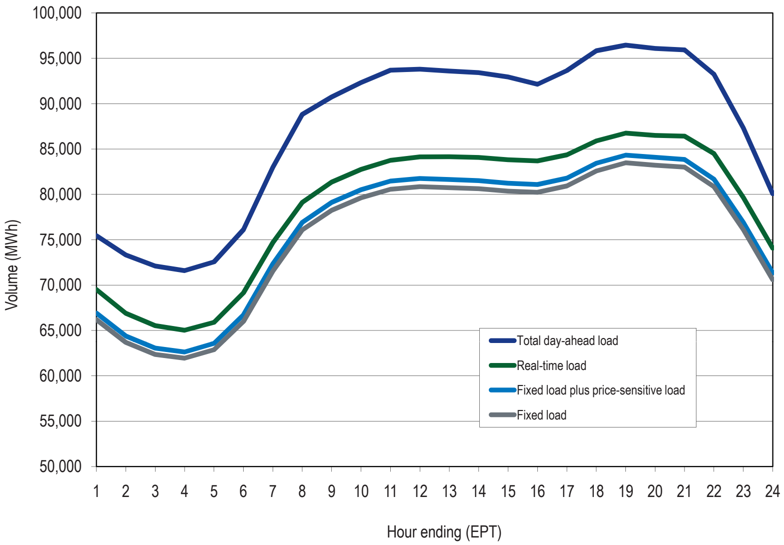
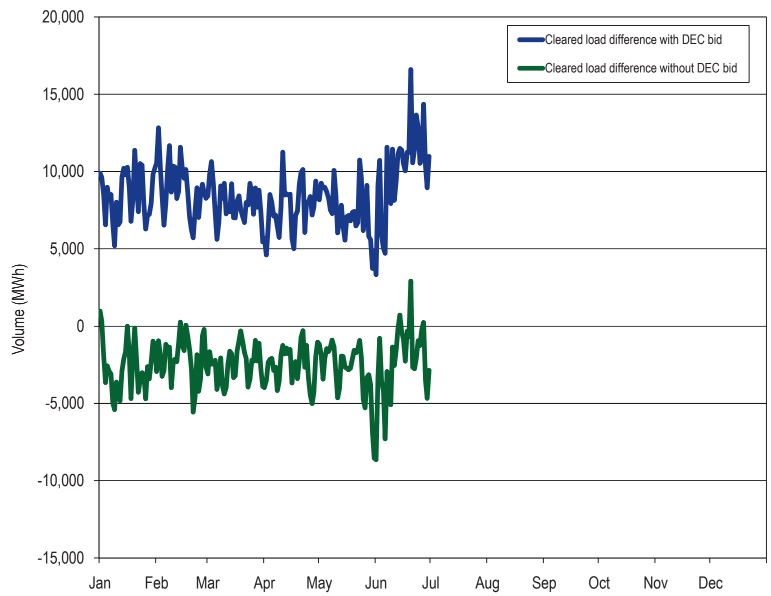


Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): January through June 2011 (See 2010 SOM, Figure 2-10)



Real-Time and Day-Ahead Generation

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

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	82,443	7,889	90,332	81,483	960	8,850
Median	81,194	7,802	89,064	80,089	1,105	8,976
Standard deviation	14,810	1,266	15,618	13,677	1,133	1,941
Peak average	91,256	8,676	99,932	89,371	1,885	10,561
Peak median	88,985	8,570	97,584	87,052	1,933	10,532
Peak standard deviation	12,599	1,064	13,162	12,011	588	1,151
Off peak average	74,578	7,188	81,766	74,443	135	7,322
Off peak median	73,386	7,079	80,500	73,368	18	7,133
Off peak standard deviation	11,929	990	12,305	10,964	964	1,341

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

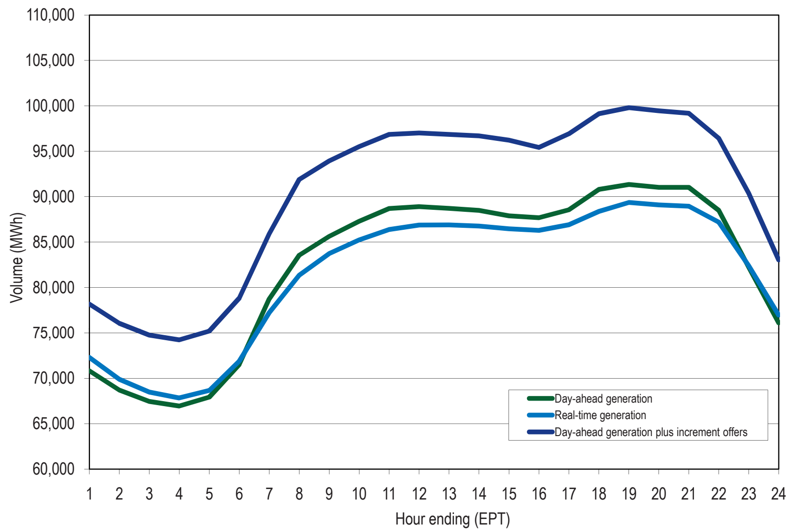
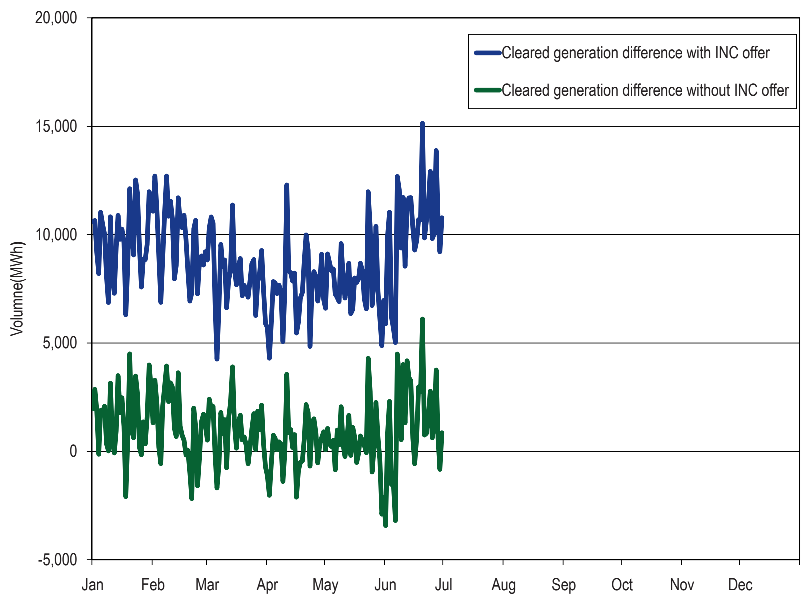


Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January through June 2011 (See 2010 SOM, Figure 2-12)



Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-15 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: January through June 2007 through 2011 (See 2010 SOM, Figure 2-13)

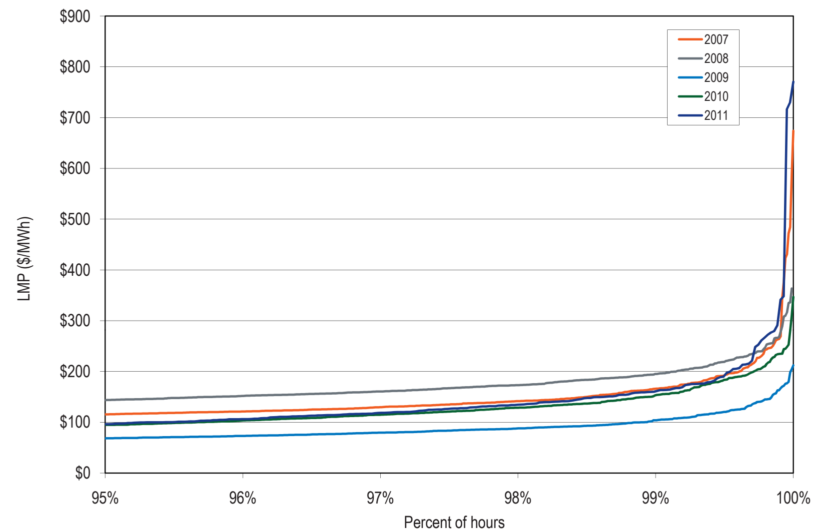
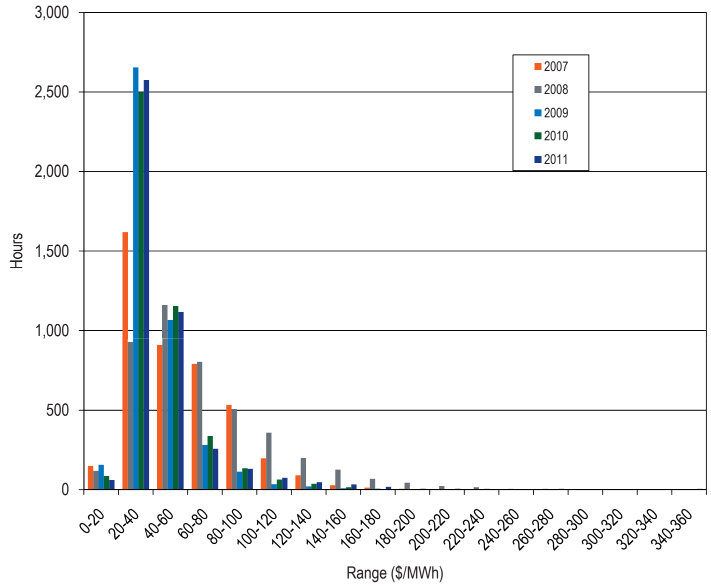


Figure 2-16 Price histogram for the PJM Real-Time Energy Market: January through June 2007 through 2011 (New Figure)



PJM Real-Time, Annual Average LMP

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

	Real-Time LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%

Zonal Real-Time, Annual Average LMP

Table 2-19 Zonal real-time, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-35)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AECO	$47.67	$51.33	$3.66	7.7%
AEP	$37.85	$40.15	$2.30	6.1%
AP	$42.65	$45.27	$2.63	6.2%
ATSI	NA	$41.94	NA	NA
BGE	$50.08	$52.07	$1.98	4.0%
ComEd	$33.60	$34.75	$1.15	3.4%
DAY	$37.68	$40.27	$2.59	6.9%
DLCO	$37.71	$39.79	$2.08	5.5%
Dominion	$49.34	$50.17	$0.83	1.7%
DPL	$48.14	$50.93	$2.78	5.8%
JCPL	$47.26	$51.39	$4.13	8.7%
Met-Ed	$46.36	$49.28	$2.93	6.3%
PECO	$46.72	$50.17	$3.46	7.4%
PENELEC	$40.77	$45.14	$4.37	10.7%
Pepco	$50.15	$51.34	$1.19	2.4%
PPL	$45.44	$50.00	$4.56	10.0%
PSEG	$48.45	$52.19	$3.74	7.7%
RECO	$46.44	$45.74	($0.70)	(1.5%)
PJM	$43.27	$45.51	$2.24	5.2%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-20 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-36)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
Delaware	$47.44	$50.27	$2.83	6.0%
Illinois	$33.60	$34.75	$1.15	3.4%
Indiana	$36.87	$39.22	$2.35	6.4%
Kentucky	$38.34	$39.59	$1.25	3.2%
Maryland	$49.92	$51.40	$1.48	3.0%
Michigan	$37.45	$39.87	$2.42	6.5%
New Jersey	$47.97	$51.74	$3.76	7.8%
North Carolina	$47.56	$48.50	$0.94	2.0%
Ohio	$37.08	$40.31	$3.23	8.7%
Pennsylvania	$44.00	$47.59	$3.60	8.2%
Tennessee	$39.38	$39.61	$0.23	0.6%
Virginia	$48.08	$48.76	$0.68	1.4%
West Virginia	$38.13	$41.31	$3.18	8.3%
District of Columbia	$50.37	$51.40	$1.03	2.0%

Hub Real-Time, Annual Average LMP

Table 2-21 Hub real-time, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-37)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AEP Gen Hub	$35.37	$38.06	$2.69	7.6%
AEP-DAY Hub	$37.12	$39.49	$2.37	6.4%
ATSI Gen Hub	NA	$41.19	$41.19	NA
Chicago Gen Hub	$32.79	$33.70	$0.90	2.8%
Chicago Hub	$33.77	$34.91	$1.13	3.4%
Dominion Hub	$48.01	$49.65	$1.64	3.4%
Eastern Hub	$48.15	$51.20	$3.06	6.4%
N Illinois Hub	$33.40	$34.52	$1.12	3.4%
New Jersey Hub	$47.86	$51.80	$3.93	8.2%
Ohio Hub	$37.16	$39.48	$2.32	6.2%
West Interface Hub	$40.10	$42.29	$2.19	5.5%
Western Hub	$43.87	$46.55	$2.68	6.1%

Real-Time, Load-Weighted, Average LMP

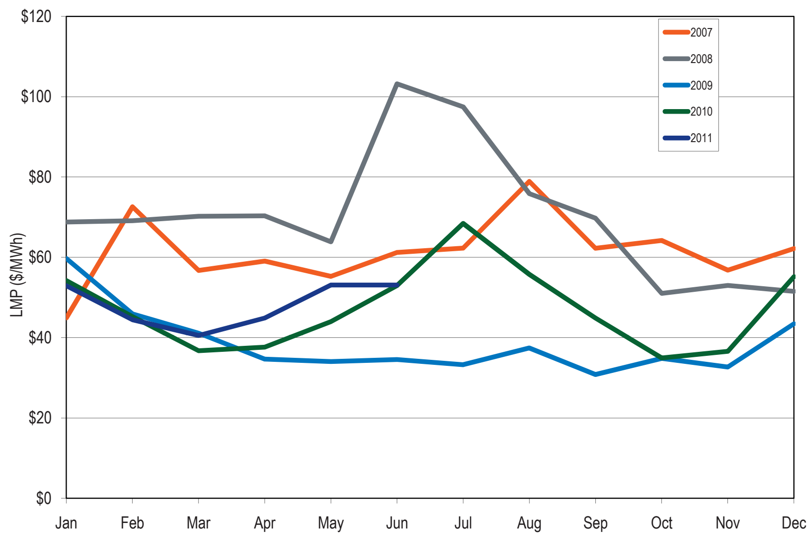
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-22 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 1998 through 2011 (See 2010 SOM, Table 2-38)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%

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

Figure 2-17 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through June 2011 (See 2010 SOM, Figure 2-14)



Zonal Real-Time, Annual, Load-Weighted, Average LMP

Table 2-23 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-39)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AECO	$51.21	$55.67	$4.47	8.7%
AEP	$39.53	$41.82	$2.29	5.8%
AP	$44.66	$47.69	$3.03	6.8%
ATSI	NA	$45.95	NA	NA
BGE	$53.92	$57.18	$3.26	6.1%
ComEd	$35.48	$36.75	$1.27	3.6%
DAY	$39.50	$42.49	$2.98	7.6%
DLCO	$39.37	$41.75	$2.38	6.1%
Dominion	$53.75	$54.64	$0.89	1.7%
DPL	$51.66	$55.43	$3.77	7.3%
JCPL	$50.97	$56.21	$5.25	10.3%
Met-Ed	$49.02	$52.81	$3.79	7.7%
PECO	$49.58	$54.04	$4.46	9.0%
PENELEC	$42.12	$47.07	$4.95	11.8%
Pepco	$54.16	$56.39	$2.23	4.1%
PPL	$47.93	$53.42	$5.48	11.4%
PSEG	$51.48	$56.10	$4.62	9.0%
RECO	$50.02	$50.25	$0.24	0.5%
PJM	$45.75	$48.47	$2.72	5.9%

Real-Time, Annual, Load-Weighted, Average LMP by Jurisdiction

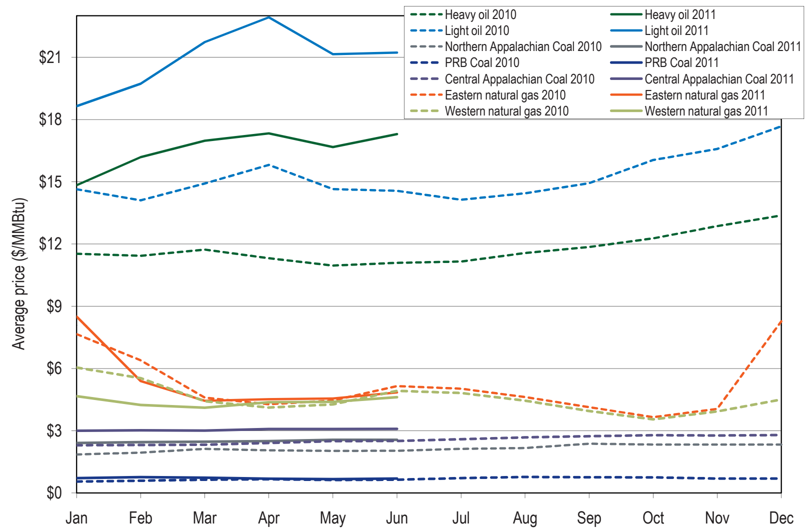
Table 2-24 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-40)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
Delaware	$50.56	$54.46	$3.90	7.7%
Illinois	$35.48	$36.75	$1.27	3.6%
Indiana	$38.03	$40.59	$2.56	6.7%
Kentucky	$40.64	$41.61	$0.97	2.4%
Maryland	$53.98	$56.41	$2.43	4.5%
Michigan	$39.05	$41.68	$2.63	6.7%
New Jersey	$51.27	$55.94	$4.68	9.1%
North Carolina	$52.03	$52.32	$0.29	0.6%
Ohio	$38.55	$42.46	$3.90	10.1%
Pennsylvania	$46.17	$50.57	$4.40	9.5%
Tennessee	$42.26	$41.71	($0.54)	(1.3%)
Virginia	$52.18	$52.85	$0.67	1.3%
West Virginia	$39.88	$43.03	$3.15	7.9%
District of Columbia	$53.53	$55.45	$1.92	3.6%

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

Fuel Cost

Figure 2-18 Spot average fuel price comparison: Calendar years 2010 through June 2011 (See 2010 SOM, Table 2-15)



Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-19 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: January through June 2007 through 2011 (See 2010 SOM, Figure 2-16)

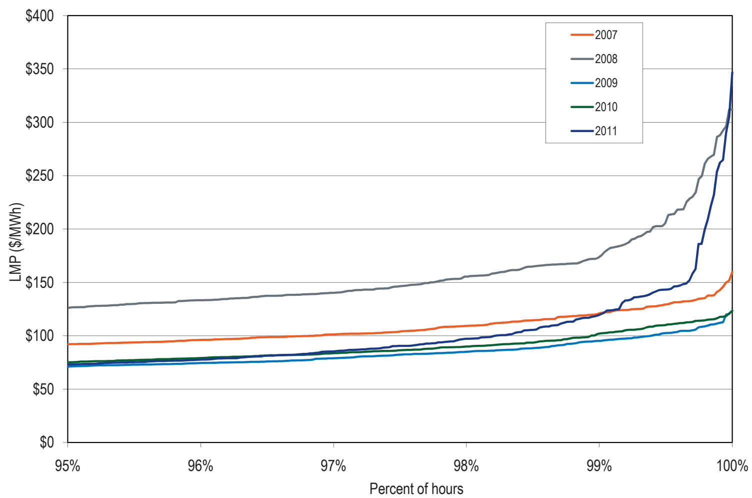
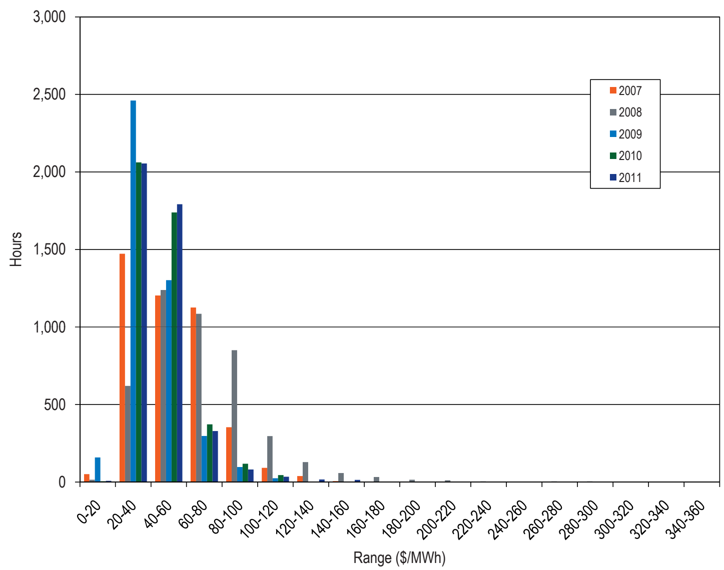


Figure 2-20 Price histogram for the PJM Day-Ahead Energy Market: January through June 2007 through 2011 (New Figure)



PJM Day-Ahead, Annual Average LMP

Table 2-25 PJM day-ahead, simple average LMP (Dollars per MWh): January through June 2000 through 2011 (See 2010 SOM, Table 2-43)

	Day-Ahead LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$30.29	$22.72	$19.75	NA	NA	NA
2001	$35.02	$31.34	$17.43	15.6%	38.0%	(11.8%)
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%

Zonal Day-Ahead, Annual Average LMP

Table 2-26 Zonal day-ahead, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-44)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AECO	$48.54	$51.31	$2.77	5.7%
AEP	$38.07	$40.00	$1.92	5.1%
AP	$43.14	$44.98	$1.84	4.3%
ATSI	NA	$43.16	NA	NA
BGE	$51.38	$51.15	($0.23)	(0.4%)
ComEd	$34.01	$34.53	$0.52	1.5%
DAY	$37.60	$39.80	$2.20	5.8%
DLCO	$38.37	$38.94	$0.58	1.5%
Dominion	$50.36	$49.10	($1.26)	(2.5%)
DPL	$48.70	$51.23	$2.52	5.2%
JCPL	$48.27	$51.22	$2.95	6.1%
Met-Ed	$47.38	$49.02	$1.63	3.4%
PECO	$47.81	$50.58	$2.76	5.8%
PENELEC	$42.38	$44.68	$2.31	5.4%
Pepco	$51.71	$50.96	($0.75)	(1.4%)
PPL	$46.45	$49.57	$3.13	6.7%
PSEG	$49.27	$52.16	$2.90	5.9%
RECO	$48.07	$48.48	$0.41	0.9%
PJM	$43.81	$44.75	$0.94	2.1%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-27 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-45)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
Delaware	$48.02	$50.42	$2.40	5.0%
Illinois	$34.01	$34.53	$0.52	1.5%
Indiana	$37.01	$39.04	$2.02	5.5%
Kentucky	$38.31	$39.41	$1.10	2.9%
Maryland	$51.14	$50.75	($0.40)	(0.8%)
Michigan	$37.51	$39.79	$2.28	6.1%
New Jersey	$48.88	$51.72	$2.85	5.8%
North Carolina	$48.75	$47.57	($1.18)	(2.4%)
Ohio	$37.05	$39.73	$2.68	7.2%
Pennsylvania	$44.97	$47.40	$2.42	5.4%
Tennessee	$39.64	$39.91	$0.27	0.7%
Virginia	$49.21	$48.07	($1.14)	(2.3%)
West Virginia	$38.47	$41.45	$2.97	7.7%
District of Columbia	$51.92	$50.94	($0.98)	(1.9%)

Day-Ahead, Load-Weighted, Average LMP

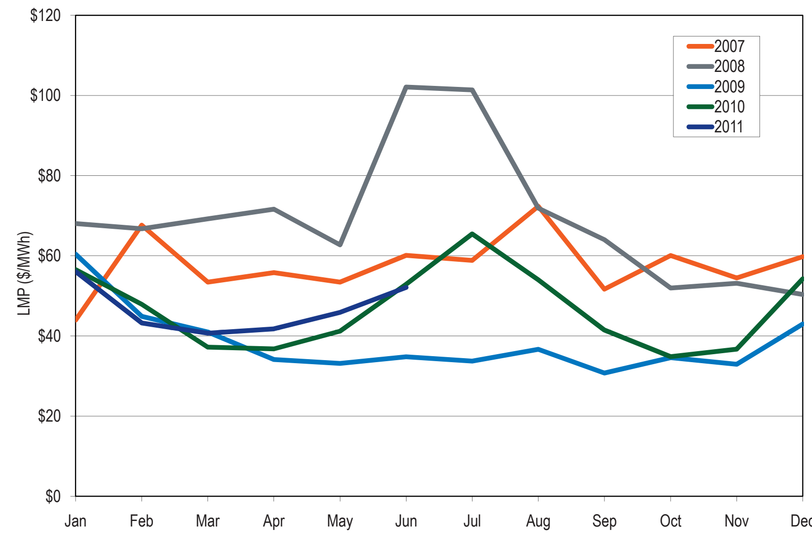
PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-28 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2000 through 2011 (See 2010 SOM, Table 2-46)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$34.12	$30.00	$20.13	NA	NA	NA
2001	$37.08	$33.91	$18.11	8.7%	13.0%	(10.0%)
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.8%	82.6%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%

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

Figure 2-21 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2007 through June 2011 (See 2010 SOM, Table 2-17)



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-29 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-47)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AECO	$52.63	$55.19	$2.56	4.9%
AEP	$39.68	$41.40	$1.72	4.3%
AP	$45.14	$46.81	$1.67	3.7%
ATSI	NA	$46.35	NA	NA
BGE	$55.13	$55.10	($0.03)	(0.1%)
ComEd	$35.49	$35.89	$0.39	1.1%
DAY	$39.30	$41.46	$2.16	5.5%
DLCO	$40.16	$40.51	$0.35	0.9%
Dominion	$54.80	$52.73	($2.07)	(3.8%)
DPL	$52.03	$55.24	$3.21	6.2%
JCPL	$51.29	$54.69	$3.40	6.6%
Met-Ed	$49.92	$51.54	$1.63	3.3%
PECO	$50.48	$53.90	$3.42	6.8%
PENELEC	$43.66	$46.55	$2.89	6.6%
Pepco	$54.53	$54.75	$0.22	0.4%
PPL	$48.88	$52.43	$3.55	7.3%
PSEG	$51.91	$55.30	$3.40	6.5%
RECO	$51.58	$51.84	$0.26	0.5%
PJM	$46.12	$47.12	$1.00	2.2%

Day-Ahead, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-30 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-48)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
Delaware	$51.06	$54.08	$3.02	5.9%
Illinois	$35.49	$35.89	$0.39	1.1%
Indiana	$38.35	$40.35	$2.00	5.2%
Kentucky	$40.18	$40.95	$0.78	1.9%
Maryland	$54.56	$54.47	($0.09)	(0.2%)
Michigan	$38.81	$41.11	$2.29	5.9%
New Jersey	$51.80	$55.02	$3.22	6.2%
North Carolina	$52.99	$51.27	($1.72)	(3.2%)
Ohio	$38.47	$41.86	$3.39	8.8%
Pennsylvania	$46.95	$49.85	$2.90	6.2%
Tennessee	$42.08	$41.71	($0.37)	(0.9%)
Virginia	$53.26	$51.35	($1.90)	(3.6%)
West Virginia	$40.20	$42.89	$2.69	6.7%
District of Columbia	$54.37	$54.29	($0.08)	(0.1%)

Marginal Losses

Table 2-31 PJM real-time, simple average LMP components (Dollars per MWh): January through June 2008 to 2011 (See 2010 SOM, Table 2-50)[9]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008 (Jan - Jun)	$70.19	$70.09	$0.06	$0.04
2009 (Jan - Jun)	$40.12	$40.04	$0.05	$0.03
2010 (Jan - Jun)	$43.27	$43.18	$0.05	$0.04
2011 (Jan - Jun)	$45.51	$45.45	$0.04	$0.03

9 The years 2006 and 2007 were removed from Table 2-31 and Table 2-35 because PJM did not begin to include marginal losses in economic dispatch and LMP models until June 1, 2007.

Table 2-32 Zonal real-time, simple average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-51)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$47.67	$43.18	$2.24	$2.25	$51.33	$45.45	$3.70	$2.18
AEP	$37.85	$43.18	($3.81)	($1.52)	$40.15	$45.45	($3.76)	($1.54)
AP	$42.65	$43.18	($0.37)	($0.17)	$45.27	$45.45	($0.18)	$0.01
ATSI	NA	NA	NA	NA	$41.94	$47.74	($5.05)	($0.76)
BGE	$50.08	$43.18	$4.72	$2.18	$52.07	$45.45	$4.62	$2.00
ComEd	$33.60	$43.18	($6.74)	($2.84)	$34.75	$45.45	($7.78)	($2.91)
DAY	$37.68	$43.18	($4.52)	($0.98)	$40.27	$45.45	($4.18)	($1.00)
DLCO	$37.71	$43.18	($3.88)	($1.59)	$39.79	$45.45	($4.41)	($1.25)
Dominion	$49.34	$43.18	$5.35	$0.81	$50.17	$45.45	$4.01	$0.72
DPL	$48.14	$43.18	$2.52	$2.44	$50.93	$45.45	$2.99	$2.49
JCPL	$47.26	$43.18	$1.79	$2.29	$51.39	$45.45	$3.62	$2.33
Met-Ed	$46.36	$43.18	$2.04	$1.13	$49.28	$45.45	$2.90	$0.94
PECO	$46.72	$43.18	$1.92	$1.61	$50.17	$45.45	$3.07	$1.65
PENELEC	$40.77	$43.18	($2.13)	($0.29)	$45.14	$45.45	($0.74)	$0.43
Pepco	$50.15	$43.18	$5.57	$1.41	$51.34	$45.45	$4.66	$1.23
PPL	$45.44	$43.18	$1.36	$0.90	$50.00	$45.45	$3.52	$1.03
PSEG	$48.45	$43.18	$2.96	$2.31	$52.19	$45.45	$4.43	$2.32
RECO	$46.44	$43.18	$1.25	$2.00	$45.74	$45.45	($1.79)	$2.08

Table 2-33 Hub real-time, simple average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-52)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.37	$43.18	($4.86)	($2.95)	$38.06	$45.45	($4.44)	($2.94)
AEP-DAY Hub	$37.12	$43.18	($4.34)	($1.73)	$39.49	$45.45	($4.18)	($1.78)
ATSI Gen Hub	NA	NA	NA	NA	$41.19	$47.68	($5.33)	($1.17)
Chicago Gen Hub	$32.79	$43.18	($7.00)	($3.38)	$33.70	$45.45	($8.25)	($3.50)
Chicago Hub	$33.77	$43.18	($6.59)	($2.82)	$34.91	$45.45	($7.66)	($2.88)
Dominion Hub	$48.01	$43.18	$4.52	$0.30	$49.65	$45.45	$3.90	$0.30
Eastern Hub	$48.15	$43.18	$2.35	$2.62	$51.20	$45.45	$3.05	$2.71
N Illinois Hub	$33.40	$43.18	($6.73)	($3.05)	$34.52	$45.45	($7.79)	($3.13)
New Jersey Hub	$47.86	$43.18	$2.43	$2.25	$51.80	$45.45	$4.08	$2.27
Ohio Hub	$37.16	$43.18	($4.34)	($1.68)	$39.48	$45.45	($4.24)	($1.73)
West Interface Hub	$40.10	$43.18	($1.68)	($1.40)	$42.29	$45.45	($1.99)	($1.17)
Western Hub	$43.87	$43.18	$0.93	($0.25)	$46.55	$45.45	$1.13	($0.03)

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

Table 2-34 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-53)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$51.21	$46.08	$2.71	$2.42	$55.67	$48.74	$4.51	$2.42
AEP	$39.53	$45.29	($4.18)	($1.59)	$41.82	$47.80	($4.35)	($1.64)
AP	$44.66	$45.45	($0.60)	($0.19)	$47.69	$48.10	($0.40)	($0.01)
ATSI	NA	NA	NA	NA	$45.95	$52.72	($6.01)	($0.75)
BGE	$53.92	$46.03	$5.54	$2.35	$57.18	$48.91	$6.06	$2.20
ComEd	$35.48	$45.16	($6.79)	($2.89)	$36.75	$47.87	($8.10)	($3.02)
DAY	$39.50	$45.49	($5.02)	($0.97)	$42.49	$48.35	($4.84)	($1.03)
DLCO	$39.37	$45.19	($4.13)	($1.69)	$41.75	$48.21	($5.10)	($1.35)
Dominion	$53.75	$46.37	$6.49	$0.89	$54.64	$48.94	$4.93	$0.77
DPL	$51.66	$46.29	$2.71	$2.66	$55.43	$48.90	$3.74	$2.80
JCPL	$50.97	$46.35	$2.16	$2.45	$56.21	$49.21	$4.43	$2.57
Met-Ed	$49.02	$45.56	$2.27	$1.19	$52.81	$48.29	$3.46	$1.05
PECO	$49.58	$45.71	$2.18	$1.69	$54.04	$48.52	$3.71	$1.81
PENELEC	$42.12	$44.90	($2.45)	($0.33)	$47.07	$47.49	($0.86)	$0.45
Pepco	$54.16	$46.11	$6.55	$1.50	$56.39	$48.96	$6.09	$1.33
PPL	$47.93	$45.52	$1.48	$0.94	$53.42	$48.09	$4.18	$1.14
PSEG	$51.48	$45.73	$3.33	$2.42	$56.10	$48.58	$5.01	$2.51
RECO	$50.02	$46.27	$1.62	$2.13	$50.25	$49.48	($1.51)	$2.28
PJM	$45.75	$45.65	$0.06	$0.04	$48.47	$48.40	$0.05	$0.03

Table 2-35 PJM day-ahead, simple average LMP components (Dollars per MWh): January through June 2008 to 2011 (See 2010 SOM, Table 2-54)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008 (Jan - Jun)	$70.12	$70.51	($0.17)	($0.23)
2009 (Jan - Jun)	$40.01	$40.27	($0.14)	($0.12)
2010 (Jan - Jun)	$43.81	$43.74	$0.07	$0.00
2011 (Jan - Jun)	$44.75	$44.94	($0.09)	($0.10)

Table 2-36 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-55)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$48.54	$43.74	$2.14	$2.66	$51.31	$44.94	$3.72	$2.65
AEP	$38.07	$43.74	($3.52)	($2.16)	$40.00	$44.94	($3.23)	($1.72)
AP	$43.14	$43.74	($0.45)	($0.16)	$44.98	$44.94	$0.02	$0.01
ATSI	NA	NA	NA	NA	$43.16	$48.03	($3.93)	($0.94)
BGE	$51.38	$43.74	$4.75	$2.89	$51.15	$44.94	$4.05	$2.16
ComEd	$34.01	$43.74	($5.95)	($3.78)	$34.53	$44.94	($7.01)	($3.41)
DAY	$37.60	$43.74	($4.25)	($1.89)	$39.80	$44.94	($4.00)	($1.14)
DLCO	$38.37	$43.74	($3.47)	($1.91)	$38.94	$44.94	($4.68)	($1.33)
Dominion	$50.36	$43.74	$5.20	$1.42	$49.10	$44.94	$3.52	$0.64
DPL	$48.70	$43.74	$2.26	$2.70	$51.23	$44.94	$3.28	$3.00
JCPL	$48.27	$43.74	$1.56	$2.97	$51.22	$44.94	$3.42	$2.85
Met-Ed	$47.38	$43.74	$2.22	$1.42	$49.02	$44.94	$3.06	$1.02
PECO	$47.81	$43.74	$1.87	$2.20	$50.58	$44.94	$3.49	$2.14
PENELEC	$42.38	$43.74	($1.50)	$0.14	$44.68	$44.94	($0.57)	$0.31
Pepco	$51.71	$43.74	$5.75	$2.21	$50.96	$44.94	$4.49	$1.52
PPL	$46.45	$43.74	$1.58	$1.12	$49.57	$44.94	$3.57	$1.07
PSEG	$49.27	$43.74	$2.34	$3.18	$52.16	$44.94	$4.26	$2.96
RECO	$48.07	$43.74	$1.52	$2.80	$48.48	$44.94	$1.22	$2.31

Zonal and PJM Day-Ahead, Annual, Load-Weighted, Average LMP Components

Table 2-37 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-56)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$52.63	$47.19	$2.46	$2.97	$55.19	$47.79	$4.47	$2.92
AEP	$39.68	$45.85	($3.91)	($2.26)	$41.40	$46.99	($3.76)	($1.83)
AP	$45.14	$45.99	($0.67)	($0.18)	$46.81	$47.02	($0.20)	($0.01)
ATSI	NA	NA	NA	NA	$46.35	$51.93	($4.59)	($0.99)
BGE	$55.13	$46.52	$5.49	$3.12	$55.10	$47.78	$4.96	$2.36
ComEd	$35.49	$45.44	($6.06)	($3.88)	$35.89	$46.72	($7.29)	($3.54)
DAY	$39.30	$46.01	($4.75)	($1.95)	$41.46	$47.33	($4.68)	($1.19)
DLCO	$40.16	$45.78	($3.61)	($2.01)	$40.51	$47.17	($5.25)	($1.41)
Dominion	$54.80	$46.85	$6.41	$1.54	$52.73	$47.93	$4.17	$0.63
DPL	$52.03	$46.72	$2.41	$2.90	$55.24	$47.91	$4.01	$3.32
JCPL	$51.29	$46.46	$1.67	$3.16	$54.69	$47.74	$3.89	$3.07
Met-Ed	$49.92	$46.02	$2.42	$1.49	$51.54	$47.00	$3.44	$1.11
PECO	$50.48	$46.18	$1.99	$2.32	$53.90	$47.41	$4.16	$2.33
PENELEC	$43.66	$45.25	($1.70)	$0.11	$46.55	$46.96	($0.74)	$0.33
Pepco	$54.53	$45.82	$6.37	$2.33	$54.75	$47.61	$5.50	$1.64
PPL	$48.88	$46.01	$1.68	$1.18	$52.43	$47.19	$4.08	$1.16
PSEG	$51.91	$46.09	$2.48	$3.34	$55.30	$47.54	$4.62	$3.14
RECO	$51.58	$46.90	$1.67	$3.01	$51.84	$47.89	$1.53	$2.42
PJM	$46.12	$46.04	$0.08	($0.00)	$47.12	$47.32	($0.10)	($0.11)

Marginal Loss Costs and Loss Credits

Table 2-38 Marginal loss costs and loss credits: January through June 2008 to 2011 (See 2010 SOM, Table 2-57)

	Total Marginal Loss Costs	Loss Credits	Percent
2008 (Jan - Jun)	$1,264,330,242	$658,658,911	52.1%
2009 (Jan - Jun)	$705,169,075	$362,534,944	51.4%
2010 (Jan - Jun)	$750,901,395	$377,493,236	50.3%
2011 (Jan - Jun)	$701,484,455	$308,396,864	44.0%

Monthly Marginal Loss Costs

Table 2-39 Marginal loss costs by type (Dollars (Millions)): January through June 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
Total	$141.0	($542.8)	$44.3	$728.1	$13.4	$12.4	($27.5)	($26.6)	$701.5

Zonal Marginal Loss Costs

Table 2-40 Marginal loss costs by control zone and type (Dollars (Millions)): January through June 2011 (See 2010 SOM, Table 2-59)

Marginal Loss Costs by Control Zone (Millions)									
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$15.0	$2.8	$0.4	$12.6	$0.2	($0.4)	($0.3)	$0.4	$13.0
AEP	($32.5)	($185.5)	$17.5	$170.5	$1.0	$6.0	($6.4)	($11.4)	$159.2
AP	$0.5	($50.2)	$4.3	$54.9	$1.2	$1.8	($1.8)	($2.4)	$52.5
ATSI	($2.4)	($4.2)	$0.3	$2.2	$0.1	$0.4	($0.4)	($0.7)	$1.5
BGE	$33.3	$7.2	$2.7	$28.7	$1.5	($0.7)	($2.3)	($0.1)	$28.6
ComEd	($117.9)	($238.3)	$5.9	$126.3	$9.2	$2.1	($0.4)	$6.8	$133.1
DAY	($1.1)	($28.8)	$3.1	$30.8	($0.1)	$1.8	($1.5)	($3.4)	$27.4
DLCO	($8.2)	($16.8)	$0.6	$9.2	($1.0)	$0.0	($0.4)	($1.5)	$7.7
Dominion	$32.9	($29.8)	$3.0	$65.6	$1.5	($0.4)	($5.7)	($3.9)	$61.8
DPL	$32.5	$4.3	$0.7	$28.9	($1.6)	$0.0	($0.6)	($2.3)	$26.6
JCPL	$35.3	$13.9	$0.3	$21.7	$0.3	($0.1)	($0.3)	$0.1	$21.8
Met-Ed	$8.2	($0.3)	$0.2	$8.7	$0.3	($0.2)	($0.1)	$0.3	$9.0
PECO	$42.9	$14.3	$0.5	$29.1	($0.1)	$0.1	($0.4)	($0.6)	$28.4
PENELEC	($2.9)	($34.5)	($0.2)	$31.4	$1.1	$0.1	$0.5	$1.4	$32.8
Pepco	$31.9	$7.0	$2.8	$27.8	($0.9)	($0.8)	($2.2)	($2.4)	$25.4
PJM	($7.4)	($19.3)	($7.4)	$4.4	($0.9)	($3.8)	$1.3	$4.2	$8.6
PPL	$23.0	($1.5)	$1.5	$25.9	$1.7	$0.8	($0.5)	$0.4	$26.3
PSEG	$56.2	$16.3	$8.0	$47.9	($0.1)	$5.9	($5.9)	($12.0)	$35.9
RECO	$1.8	$0.4	$0.1	$1.4	$0.0	($0.4)	($0.1)	$0.3	$1.8
Total	$141.0	($542.8)	$44.3	$728.1	$13.4	$12.4	($27.5)	($26.6)	$701.5

Table 2-41 Monthly marginal loss costs by control zone (Dollars (Millions)): January through June 2011 (See 2010 SOM, Table 2-60)

	Marginal Loss Costs by Control Zone (Millions)						
	Jan	Feb	Mar	Apr	May	Jun	Grand Total
AECO	$2.9	$2.0	$1.8	$1.5	$1.5	$3.2	$13.0
AEP	$41.9	$25.6	$23.8	$19.2	$18.2	$30.5	$159.2
AP	$14.3	$8.4	$7.7	$6.5	$6.6	$9.1	$52.5
ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$1.5	$1.5
BGE	$6.5	$5.0	$3.9	$3.2	$3.8	$6.3	$28.6
ComEd	$32.3	$21.9	$23.1	$17.8	$15.3	$22.7	$133.1
DAY	$5.2	$5.0	$4.5	$2.8	$4.1	$5.9	$27.4
DLCO	$2.2	$1.6	$0.7	$0.8	$1.2	$1.2	$7.7
Dominion	$19.8	$11.6	$9.7	$4.3	$8.2	$8.2	$61.8
DPL	$7.7	$5.3	$3.6	$2.7	$2.6	$4.7	$26.6
JCPL	$6.2	$4.1	$3.1	$2.5	$2.3	$3.6	$21.8
Met-Ed	$2.1	$1.4	$1.4	$1.2	$1.5	$1.6	$9.0
PECO	$6.6	$3.5	$3.5	$3.7	$4.9	$6.3	$28.4
PENELEC	$8.9	$5.3	$3.6	$3.1	$5.0	$6.9	$32.8
Pepco	$5.9	$3.7	$3.9	$3.1	$3.7	$5.1	$25.4
PJM	$6.9	$4.3	$0.2	($0.6)	$0.1	($2.4)	$8.6
PPL	$8.6	$4.7	$3.0	$2.6	$3.1	$4.4	$26.3
PSEG	$7.3	$6.1	$6.3	$4.6	$5.2	$6.4	$35.9
RECO	$0.5	$0.3	$0.3	$0.2	$0.2	$0.3	$1.8
Total	$185.7	$119.9	$104.0	$79.2	$87.3	$125.4	$701.5

Virtual Offers and Bids

Table 2-42 Monthly volume of cleared and submitted INCs, DECs: January through June 2011 (See 2010 SOM, Table 2-61)

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	8,137	14,299	218	1,077	11,135	17,917	224	963
Feb	8,532	16,263	215	1,672	11,076	17,355	230	1,034
Mar	7,230	13,164	201	1,059	10,435	16,343	219	982
Apr	7,222	12,516	185	984	10,211	16,199	202	846
May	7,443	12,161	220	835	10,250	15,956	243	800
Jun	8,405	14,171	238	1,084	11,648	17,542	279	1,015
Annual	7,817	13,726	213	1,110	10,786	16,878	233	938

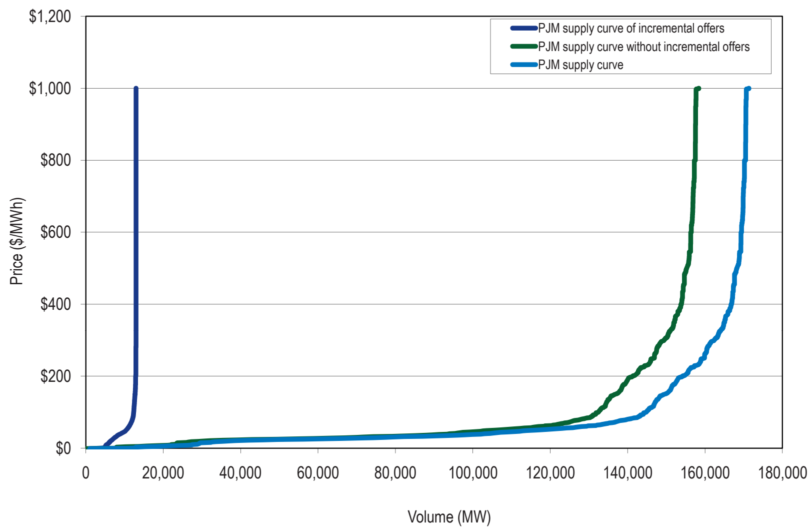
Table 2-43 PJM virtual bids by type of bid parent organization (MW): January through June 2011 (See 2010 SOM, Table 2-63)

Jan - Jun	Category	Total Virtual Bids MW	Percentage
2011	Financial	65,263,359	49.1%
2011	Physical	67,647,808	50.9%
2011	Total	132,911,167	100.0%

Table 2-44 PJM virtual offers and bids by top ten aggregates (MW): January through June 2011 (See 2010 SOM, Table 2-64)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	13,521,348	15,020,627	28,541,975
N ILLINOIS HUB	HUB	5,167,001	8,250,732	13,417,732
AEP-DAYTON HUB	HUB	2,982,170	3,496,006	6,478,176
PECO	ZONE	888,857	2,386,768	3,275,624
MISO	INTERFACE	139,799	2,746,674	2,886,472
SOUTHIMP	INTERFACE	2,829,561	0	2,829,561
PPL	ZONE	148,840	1,910,488	2,059,328
SRIVER 230 KV NUG GE	GEN	799,726	796,024	1,595,750
ComEd	ZONE	1,336,079	193,406	1,529,485
BGE	ZONE	71,238	1,261,260	1,332,498
Top ten total		27,884,617	36,061,984	63,946,601
PJM total		59,610,629	73,300,538	132,911,167
Top ten total as percent of PJM total		47.0%	49.0%	48.0%

Figure 2-22 PJM day-ahead aggregate supply curves: 2011 example day (See 2010 SOM, Figure 2-18)



Price Convergence

Table 2-45 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2011 (See 2010 SOM, Table 2-65)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$44.75	$45.51	$0.76	1.7%
Median	$40.85	$37.40	($3.45)	(9.2%)
Standard deviation	$19.53	$32.52	$12.99	39.9%
Peak average	$52.44	$54.09	$1.64	3.0%
Peak median	$47.54	$42.58	($4.96)	(11.6%)
Peak standard deviation	$22.28	$40.61	$18.32	45.1%
Off peak average	$37.89	$37.86	($0.03)	(0.1%)
Off peak median	$34.62	$33.44	($1.18)	(3.5%)
Off peak standard deviation	$13.38	$20.16	$6.77	33.6%

Table 2-46 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2000 through 2011 (See 2010 SOM, Table 2-66)

Jan - Jun	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$30.29	$27.19	($3.10)	(10.2%)
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%

Table 2-47 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2007 through June 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%	0	0.00%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	1	0.02%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	27	0.64%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	2,773	64.49%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	1,414	97.05%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	105	99.47%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	16	99.84%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.88%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	2	99.93%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.93%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.93%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.93%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.93%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%

Figure 2-23 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through June 2011 (See 2010 SOM, Figure 2-19)

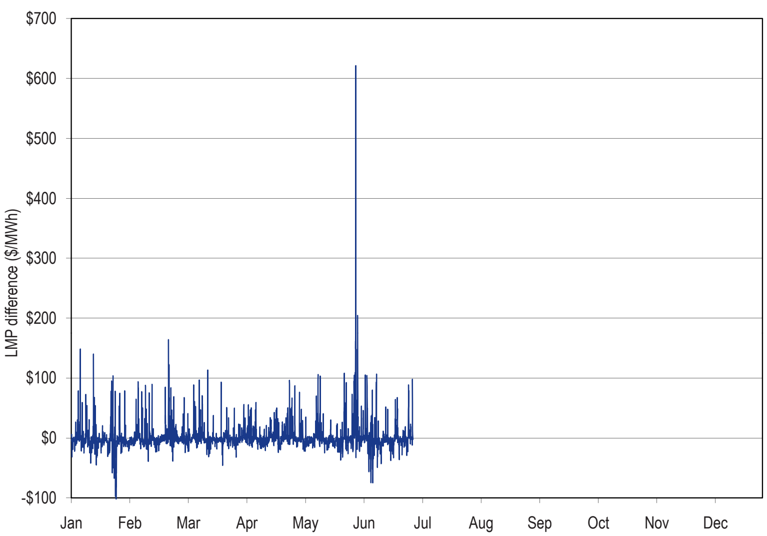
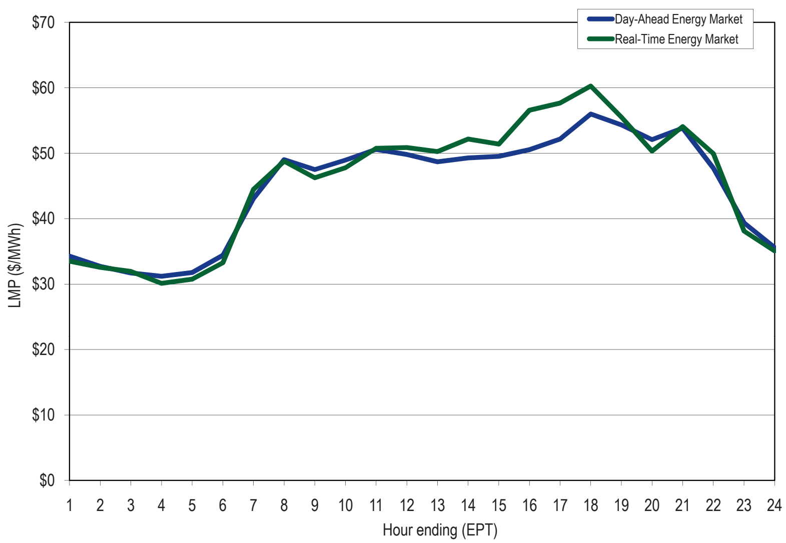


Figure 2-24 Monthly simple average of real-time minus day-ahead LMP: January through June 2011 (See 2010 SOM, Figure 2-20)

Figure 2-25 PJM system simple hourly average LMP: January through June 2011 (See 2010 SOM, Figure 2-21)



Zonal Price Convergence

Table 2-48 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2011 (See 2010 SOM, Table 2-68)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$51.31	$51.33	$0.02	0.0%
AEP	$40.00	$40.15	$0.16	0.4%
AP	$44.98	$45.27	$0.30	0.7%
ATSI	$43.16	$41.94	($1.23)	(2.8%)
BGE	$51.15	$52.07	$0.92	1.8%
ComEd	$34.53	$34.75	$0.22	0.6%
DAY	$39.80	$40.27	$0.47	1.2%
DLCO	$38.94	$39.79	$0.85	2.2%
Dominion	$49.10	$50.17	$1.07	2.2%
DPL	$51.23	$50.93	($0.30)	(0.6%)
JCPL	$51.22	$51.39	$0.17	0.3%
Met-Ed	$49.02	$49.28	$0.27	0.5%
PECO	$50.58	$50.17	($0.40)	(0.8%)
PENELEC	$44.68	$45.14	$0.45	1.0%
Pepco	$50.96	$51.34	$0.38	0.8%
PPL	$49.57	$50.00	$0.42	0.9%
PSEG	$52.16	$52.19	$0.03	0.1%
RECO	$48.48	$45.74	($2.73)	(5.6%)

Price Convergence by Jurisdiction

Table 2-49 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2011 (See 2010 SOM, Table 2-69)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$50.42	$50.27	($0.15)	(0.3%)
Illinois	$34.53	$34.75	$0.22	0.6%
Indiana	$39.04	$39.22	$0.19	0.5%
Kentucky	$39.41	$39.59	$0.18	0.5%
Maryland	$50.75	$51.40	$0.65	1.3%
Michigan	$39.79	$39.87	$0.08	0.2%
New Jersey	$51.72	$51.74	$0.01	0.0%
North Carolina	$47.57	$48.50	$0.92	1.9%
Ohio	$39.73	$40.31	$0.58	1.5%
Pennsylvania	$47.40	$47.59	$0.20	0.4%
Tennessee	$39.91	$39.61	($0.30)	(0.8%)
Virginia	$48.07	$48.76	$0.69	1.4%
West Virginia	$41.45	$41.31	($0.14)	(0.3%)
District of Columbia	$50.94	$51.40	$0.46	0.9%

Load and Spot Market

Real-Time Load and Spot Market

Table 2-50 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2010 through June 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%						
Aug	10.6%	20.5%	68.9%						
Sep	12.0%	22.3%	65.7%						
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%	10.5%	27.1%	62.5%	(1.3%)	6.9%	(5.5%)

Day-Ahead Load and Spot Market

Table 2-51 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2010 through June 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%						
Aug	4.8%	19.3%	75.9%						
Sep	4.6%	20.7%	74.8%						
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%	70.2%	0.8%	4.8%	(5.6%)

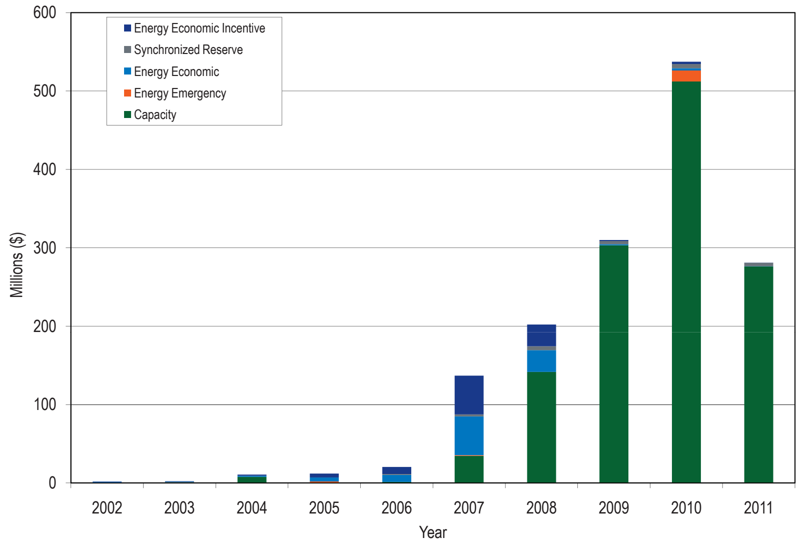
Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-52 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 (Full option) or Capacity Only	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	**Full Option:** Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payments applicable during PJM declared Emergency Events mandatory curtailments. **Capacity only:** No energy payments	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payments applicable during PJM declared Emergency Events mandatory curtailments.	Energy payment based on LMP less generation component of retail rate. Energy payment for hours of voluntary curtailment.

Figure 2-26 Demand Response revenue by market: Calendar years 2002 through 2010 and January through June 2011[10] (See 2010 SOM, Figure 2-22)



10 PJM data currently available show no revenue for the categories "Energy Economic" and "Energy Emergency" for the first six months of 2011.

Economic Program

Table 2-53 Economic Program registration on peak load days: Calendar years 2002 to 2010 and January through June 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
8-Jun-11	834	1,985.1

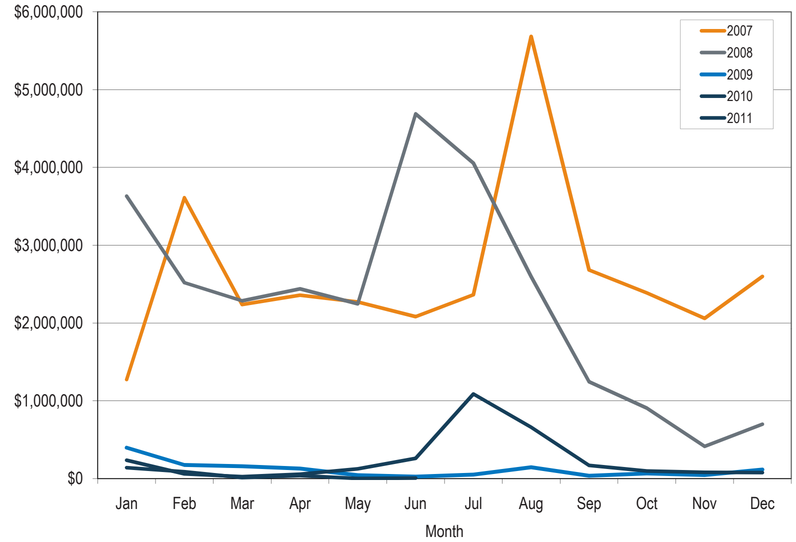
Table 2-54 Economic Program registrations on the last day of the month: January 2008 through June 2011 (See 2010 SOM, Table 2-74)

	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		
Aug	4,815	3,232	1,653	2,650	1,616	2,398		
Sep	4,836	3,263	1,879	2,727	1,609	2,447		
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	1,529	2,384

Table 2-55 Distinct registrations and sites in the Economic Program: June 8, 2011[11] (See 2010 SOM, Table 2-75)

	Registrations	Sites	MW
AECO	28	31	13.3
AEP	51	75	134.1
AP	29	41	103.1
ATSI	0	0	0.0
BGE	70	74	903.6
ComEd	68	79	48.1
DAY	5	5	7.2
DLCO	32	36	58.4
Dominion	62	62	181.6
DPL	28	33	62.5
JCPL	22	30	79.4
Met-Ed	46	54	64.1
PECO	180	238	104.3
PENELEC	39	48	50.7
Pepco	14	14	12.7
PPL	88	120	123.3
PSEG	71	128	38.7
RECO	1	1	0.3
Total	834	1,069	1,985.1

Figure 2-27 Economic Program payments by month: Calendar years 2007[12] through 2010 and January through June 2011 (See 2010 SOM, Figure 2-23)



11 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 2-55 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

12 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 2-27 do not include these incentive payments.

Table 2-56 PJM Economic Program participation by zone: January through June 2010 and 2011 (See 2010 SOM, Table 2-78)

	Credits			MWh Reductions		
	2010	2011	Percent Change	2010	2011	Percent Change
AECO	$2,262	$0	(100%)	25	0	(100%)
AEP	$0	$0	0%	0	0	0%
AP	$43,037	$7,030	(84%)	2,349	152	(94%)
ATSI	$0	$0	0%	0	0	0%
BGE	$0	$6,336	NA	0	19	NA
ComEd	$15,540	$0	(100%)	1,022	0	(100%)
DAY	$0	$0	0%	0	0	0%
DLCO	$0	$44	NA	0	2	NA
Dominion	$489,404	$216,244	(56%)	8,031	2,381	(70%)
DPL	$0	$0	0%	0	0	0%
JCPL	$948	$0	(100%)	14	0	(100%)
Met-Ed	$310	$0	(100%)	21	0	(100%)
PECO	$198,193	$55,769	(72%)	8,300	1,292	(84%)
PENELEC	$331	$0	(100%)	18	0	(100%)
Pepco	$776	$0	(100%)	17	0	(100%)
PPL	$11,049	$0	(100%)	422	3	(99%)
PSEG	$5	$0	0%	4	0	0%
RECO	$0	$0	0%	0	0	0%
Total	$761,854	$285,423	(63%)	20,225	3,848	(81%)

Table 2-57 Settlement days submitted by month in the Economic Program: Calendar years 2007 through 2010 and January through June 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	
Aug	3,962	3,848	3,760	2,158	
Sep	3,388	3,264	2,570	660	
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	1,935

Table 2-58 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2010 and January through June 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		
Aug	17	306	15	400	14	302		
Sep	17	312	11	181	11	97		
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	13	438

Table 2-59 Hourly frequency distribution of Economic Program MWh reductions and credits: January through June 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	0.15%	6	0.15%	$105	0.04%	$105	0.04%
2	6	0.17%	12	0.31%	$193	0.07%	$298	0.10%
3	12	0.32%	24	0.63%	$619	0.22%	$917	0.32%
4	4	0.10%	28	0.74%	$61	0.02%	$978	0.34%
5	8	0.21%	36	0.95%	$51	0.02%	$1,028	0.36%
6	36	0.92%	72	1.87%	$725	0.25%	$1,754	0.61%
7	779	20.24%	851	22.11%	$63,898	22.39%	$65,652	23.00%
8	1,080	28.06%	1,930	50.17%	$99,668	34.92%	$165,320	57.92%
9	450	11.68%	2,380	61.85%	$31,577	11.06%	$196,897	68.98%
10	177	4.60%	2,557	66.44%	$9,281	3.25%	$206,178	72.24%
11	130	3.39%	2,687	69.83%	$4,746	1.66%	$210,924	73.90%
12	98	2.55%	2,785	72.39%	$1,764	0.62%	$212,688	74.52%
13	116	3.02%	2,901	75.40%	$2,158	0.76%	$214,846	75.27%
14	80	2.08%	2,981	77.48%	$3,361	1.18%	$218,207	76.45%
15	95	2.47%	3,076	79.95%	$5,900	2.07%	$224,108	78.52%
16	125	3.25%	3,201	83.20%	$8,684	3.04%	$232,791	81.56%
17	194	5.04%	3,395	88.23%	$12,928	4.53%	$245,719	86.09%
18	194	5.04%	3,589	93.27%	$22,816	7.99%	$268,535	94.08%
19	173	4.50%	3,762	97.77%	$13,686	4.79%	$282,221	98.88%
20	25	0.64%	3,787	98.41%	$1,306	0.46%	$283,527	99.34%
21	26	0.66%	3,812	99.08%	$1,156	0.41%	$284,683	99.74%
22	18	0.47%	3,830	99.54%	$540	0.19%	$285,223	99.93%
23	12	0.30%	3,842	99.85%	$144	0.05%	$285,367	99.98%
24	6	0.15%	3,848	100.00%	$56	0.02%	$285,423	100.00%

Table 2-60 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through June 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	6	0.15%	6	0.15%	$18	0.01%	$18	0.01%
$25 to $50	736	19.14%	742	19.29%	$8,382	2.94%	$8,400	2.94%
$50 to $75	962	25.01%	1,705	44.30%	$22,118	7.75%	$30,518	10.69%
$75 to $100	305	7.93%	2,010	52.23%	$14,493	5.08%	$45,012	15.77%
$100 to $125	268	6.95%	2,277	59.19%	$14,493	5.08%	$59,505	20.85%
$125 to $150	537	13.95%	2,814	73.13%	$48,311	16.93%	$107,816	37.77%
$150 to $200	431	11.21%	3,246	84.34%	$56,117	19.66%	$163,933	57.44%
$200 to $250	301	7.83%	3,547	92.17%	$50,653	17.75%	$214,586	75.18%
$250 to $300	201	5.22%	3,748	97.39%	$41,869	14.67%	$256,455	89.85%
> $300	100	2.61%	3,848	100.00%	$28,968	10.15%	$285,423	100.00%

Emergency Program

Load Management Program

Table 2-61 Zonal monthly capacity credits: January through June 2011 (See 2010 SOM, Table 2-85)

Zone	January	February	March	April	May	June	Total
AECO	$515,251	$465,388	$515,251	$498,630	$515,251	$332,740	$2,842,509
AEP	$7,718,744	$6,971,769	$7,718,744	$7,469,752	$7,718,744	$5,220,226	$42,817,980
APS	$4,272,819	$3,859,321	$4,272,819	$4,134,986	$4,272,819	$3,300,774	$24,113,539
ATSI	$0	$0	$0	$0	$0	$4,665	$4,665
BGE	$5,039,828	$4,552,103	$5,039,828	$4,877,253	$5,039,828	$3,513,455	$28,062,294
ComEd	$8,156,971	$7,367,587	$8,156,971	$7,893,843	$8,156,971	$5,965,794	$45,698,137
DAY	$1,151,545	$1,040,105	$1,151,545	$1,114,399	$1,151,545	$797,889	$6,407,029
DLCO	$5,447,494	$4,920,317	$5,447,494	$5,271,768	$5,447,494	$3,851,851	$30,386,419
Dominion	$1,088,233	$982,920	$1,088,233	$1,053,128	$1,088,233	$790,970	$6,091,718
DPL	$1,118,544	$1,010,298	$1,118,544	$1,082,462	$1,118,544	$2,340	$5,450,733
JCPL	$1,301,034	$1,175,128	$1,301,034	$1,259,066	$1,301,034	$854,729	$7,192,025
Met-Ed	$1,205,089	$1,088,468	$1,205,089	$1,166,215	$1,205,089	$880,176	$6,750,126
PECO	$2,826,229	$2,552,723	$2,826,229	$2,735,060	$2,826,229	$2,300,272	$16,066,741
PENELEC	$1,827,610	$1,650,744	$1,827,610	$1,768,654	$1,827,610	$1,335,716	$10,237,944
Pepco	$1,307,359	$1,180,840	$1,307,359	$1,265,186	$1,307,359	$1,137,037	$7,505,139
PPL	$4,115,164	$3,716,922	$4,115,164	$3,982,417	$4,115,164	$2,651,235	$22,696,067
PSEG	$2,536,813	$2,291,315	$2,536,813	$2,454,980	$2,536,813	$1,431,581	$13,788,316
RECO	$9,266	$8,369	$9,266	$8,967	$9,266	$21,799	$66,934
Total	$49,637,993	$44,834,317	$49,637,993	$48,036,767	$49,637,993	$34,393,250	$276,178,314

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 six 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

- Operating reserve charges increased $24,826,194, or 10.1 percent, from $270,734,409 in the first six months of 2011 compared to $245,908,215 in the first six months of 2010. Reliability credits decreased $9,827,203, or 18.2 percent, in the first six months of 2011 compared to the first six months of 2010, and deviation credits increased $10,216,220, or 11.8 percent.

- Reliability charges were $44,230,427, 31.3 percent of all balancing operating reserve charges for the first six months 2011, and deviation charges were $97,092,749, or 68.7 percent.

- The Western reliability rate in the first six months of 2011 is the highest balancing operating reserve rate, averaging $.9802/MWh. The average daily RTO deviation rate of $.1619/MWh decreased in the first six months of 2011 when compared to the rate of $.7360/MWh in the first six months of 2010.

- Operating reserve credits for dispatchable transactions, which are a subset of pool-scheduled spot market import transactions, or balancing transaction operating reserve credits, for the months January through June 2011, were $1,252,846. The year with the next highest first half total balancing transaction operating reserve credits was in 2008, when credits were $818,778.

- 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 34.3 percent of total operating reserve credits in the first six months of 2011, compared to 42.3 percent in the first six months of 2010. In the first six months of 2011, the top generation owner received 30.9 percent of the total operating reserve credits paid.

- The regional concentration of balancing operating reserves for the first six months of 2011 is slightly lower than the first six months of 2010, with 31.1 percent of the credits being paid to units operating in the PSEG zone, 24.7 percent in the Dominion zone, and 11.2 percent in the AEP zone.

- In the first six months of 2011, coal units provided 47.6 percent, nuclear units 34.8 percent and gas units 12.8 percent of total generation. Compared to the first six months of 2010, generation from coal units decreased 5.6 percent, and generation from nuclear units decreased 1.6 percent. Generation from natural gas units increased 42.4 percent, and generation from oil units increased 1.8 percent.

- At the end of June 2011, 80,787 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 167,000 MW in 2011. Wind projects account for approximately 39,656 MW of capacity, 49.1 percent of the capacity in the queues and combined-cycle projects account for 20,304 MW, 25.1 percent, of the capacity in the queues.

- Three large plants (over 550 MW) have started generating in PJM since January 1, 2011. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 3,409 MW of nameplate capacity has been added in PJM in 2011 (excluding the ATSI zone additions), the most since 2003.

Recommendations

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

Overview

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through June 30, 2011, PJM installed capacity resources increased from 166,410.2 MW on January 1 to 179,813.1 as a result of the integration of American Transmission Systems, Inc. (ATSI) into the PJM footprint.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of June 30, 2011, 41.9 percent was coal; 28.2 percent was gas; 18.4 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.** In January through June 2011, coal provided 47.6 percent, nuclear 34.8 percent, gas 12.8 percent, oil 0.2 percent, hydroelectric 2.2 percent, solid waste 0.7 percent and wind 1.7 percent of total generation.

- **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 Impact and Renewables

- **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 28 states, including all of the PJM states except Delaware, and also excepting the District of Columbia, to reduce certain power plant emissions 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). 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 District of Columbia Circuit directing revisions compliant with the requirements of the Clean Air Act. The CSAPR becomes effective January 1, 2012, replacing CAIR.

  The CSAPR requires 21 states, including all of the PJM states except Delaware, and also excepting D.C., to 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 NOX 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. Significant additional SO_2 emission reductions are required in 2014 from certain states, including all of the PJM states except Delaware, and also excepting D.C. 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, respectively, by 73 percent (6.4 million tons/year) and 54 percent (1.4 million tons/year).

  The rule implements an air quality-assured trading program for states in the CSAPR region. Each of the states covered by this rule has pollution limits set by the EPA. 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, subject to provisions intended to assure that each state will meet its individual obligations.

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 six months of 2011.** Operating reserve charges increased 10.1 percent in the first six months of 2011 compared to the first six months of 2010. Reliability credits decreased $9,827,203, or 18.2 percent, in the first six months of 2011 compared to the first six months of 2010, and deviation credits increased $10,216,220, or 11.8 percent.

  The overall increase in operating reserve charges in 2011 is comprised of a 2.4 percent increase in day-ahead operating reserve charges, a 15.6 percent decrease in synchronous condensing charges and a 12.0 percent increase in balancing operating reserve charges.

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 non market 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.

Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

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

	1-Jan-11		31-May-11		1-Jun-11		30-Jun-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%	75,308.3	41.9%
Gas	47,736.6	28.7%	47,831.1	28.7%	50,729.0	28.0%	50,733.5	28.2%
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	18.4%
Oil	10,949.5	6.6%	10,854.1	6.5%	11,212.3	6.2%	11,212.3	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%	646.0	0.4%
Total	166,410.2	100.0%	166,611.9	100.0%	181,438.7	100.0%	179,813.1	100.0%

Energy Production by Fuel Source

Table 3-2 PJM generation (By fuel source (GWh)): January through June 2010 and 2011[1] (See 2010 SOM, Table 3-43)

	2010 (Jan-Jun)		2011 (Jan-Jun)		Change in Output
	GWh	Percent	GWh	Percent	
Coal	180,693.4	50.8%	170,495.9	47.6%	(5.6%)
Standard Coal	175,212.6	49.3%	164,911.8	46.0%	0.0%
Waste Coal	5,480.9	1.5%	5,584.1	1.6%	0.0%
Nuclear	126,789.7	35.7%	124,708.7	34.8%	(1.6%)
Gas	32,252.9	9.1%	45,921.7	12.8%	42.4%
Natural Gas	31,456.6	8.8%	45,081.2	12.6%	43.3%
Landfill Gas	796.1	0.2%	840.5	0.2%	5.6%
Biomass Gas	0.2	0.0%	0.1	0.0%	(64.9%)
Hydroelectric	8,146.2	2.3%	7,726.9	2.2%	(5.1%)
Wind	4,183.0	1.2%	6,084.5	1.7%	45.5%
Waste	2,573.7	0.7%	2,596.4	0.7%	0.9%
Solid Waste	2,024.9	0.6%	1,981.4	0.6%	(2.1%)
Miscellaneous	548.8	0.2%	614.9	0.2%	12.1%
Oil	875.5	0.2%	891.7	0.2%	1.8%
Heavy Oil	687.0	0.2%	750.1	0.2%	9.2%
Light Oil	175.0	0.0%	129.7	0.0%	(25.9%)
Diesel	10.3	0.0%	7.8	0.0%	(24.3%)
Kerosene	3.2	0.0%	4.0	0.0%	26.8%
Jet Oil	0.1	0.0%	0.0	0.0%	(51.1%)
Solar	2.1	0.0%	21.6	0.0%	919.1%
Battery	0.2	0.0%	0.1	0.0%	(26.6%)
Total	355,516.8	100.0%	358,447.4	100.0%	0.8%

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

Table 3-3 PJM capacity factor (By unit type (GWh)); January through June 2010 and 2011[2] [3] (New table)

	2010 (Jan-Jun)		2011 (Jan-Jun)	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.2	4.6%	0.1	3.4%
Combined Cycle	28,041.9	28.8%	42,100.8	41.9%
Combustion Turbine	2,278.1	1.9%	2,002.7	1.6%
Diesel	216.4	12.7%	233.1	13.5%
Diesel (Landfill gas)	508.2	37.7%	509.4	36.6%
Nuclear	126,789.7	92.7%	124,708.7	90.8%
Pumped Storage Hydro	3,850.5	16.1%	3,390.8	14.2%
Run of River Hydro	4,295.7	42.2%	4,336.1	42.6%
Solar	2.1	14.9%	21.6	14.4%
Steam	185,296.8	53.1%	175,326.9	49.0%
Wind	4,183.0	28.9%	6,084.5	32.1%

Planned Generation Additions

Table 3-4 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through June 30, 2011[4] (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-Jun)	3,409

2 The capacity factors for wind and solar unit types described in this table are based on nameplate capacity values.
3 The capacity factor for solar units in 2010 contains a significantly smaller sample of units than 2011.
4 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

PJM Generation Queues

Table 3-5 Queue comparison (MW): June 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	17,935	(7,443)	(29%)
2012	13,261	15,827	2,567	19%
2013	11,244	12,614	1,370	12%
2014	13,888	14,788	900	6%
2015	5,960	11,419	5,459	92%
2016	1,350	2,850	1,500	111%
2017	2,140	2,160	20	1%
2018	3,194	3,194	0	0%
Total	76,415	80,787	4,372	6%

Table 3-6 Capacity in PJM queues (MW): At June 30, 2011[5, 6] (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	14,957	19,602
C Expired 31-Jul-99	0	531	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	1,086	555	17,409	19,050
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	148	160	2,335	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	1,678	1,470	362	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	4,687	691	1,183	16,194	22,755
S Expired 31-Jul-07	2,357	2,507	1,055	11,475	17,393
T Expired 31-Jan-08	11,399	801	573	14,845	27,617
U Expired 31-Jan-09	6,505	222	575	26,106	33,407
V Expired 31-Jan-10	12,388	99	411	4,253	17,150
W Expired 31-Jan-11	17,849	3	446	6,198	24,496
X Expires 31-Jan-12	11,121	0	60	37	11,218
Total	71,652	29,763	9,135	198,156	308,706

Table 3-7 Average project queue times (days): At June 30, 2011 (See 2010 SOM, Table 3-47)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	789	645	0	4,420
In-Service	776	653	0	3,602
Suspended	2,435	791	890	3,849
Under Construction	1,207	847	0	4,370
Withdrawn	507	496	0	3,186

Distribution of Units in the Queues

Table 3-8 Capacity additions in active or under-construction queues by control zone (MW): At June 30, 2011 (See 2010 SOM, Table 3-48)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	1,255	762	17	0	0	961	665	0	2,159	5,818
AEP	2,545	580	10	170	0	161	2,397	0	14,097	19,960
AP	958	0	6	98	0	372	597	32	1,065	3,129
ATSI	268	72	22	0	0	0	135	0	947	1,444
BGE	0	0	29	0	1,640	0	132	0	0	1,801
ComEd	1,080	398	103	23	613	55	1,366	20	15,412	19,069
DAY	0	0	2	112	0	60	12	0	1,440	1,626
DLCO	0	0	0	0	91	0	0	0	0	91
Dominion	2,095	615	18	0	1,774	154	322	32	1,634	6,644
DPL	600	96	0	0	0	159	20	50	855	1,780
JCPL	1,995	27	30	0	0	1,284	0	0	0	3,336
Met-Ed	1,760	7	18	0	24	110	0	3	0	1,922
PECO	663	7	17	0	490	26	0	2	0	1,206
PENELEC	905	0	12	0	0	136	50	0	1,530	2,632
Pepco	2,309	0	6	0	0	10	0	0	0	2,325
PPL	1,354	139	14	3	1,600	166	33	20	498	3,826
PSEG	2,518	1,083	4	0	50	397	105	2	20	4,178
Total	20,304	3,786	308	406	6,282	4,051	5,833	161	39,656	80,787

5 The *2011 Quarterly State of the Market Report for PJM: January through June* contains all projects in the queue including reratings of existing generating units and energy only resources.
6 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Table 3-9 Capacity additions in active or under-construction queues by LDA (MW): At June 30, 2011[7] (See 2010 SOM, Table 3-49)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	7,030	1,975	68	0	540	2,827	790	54	3,034	16,318
SWMAAC	2,309	0	35	0	1,640	10	132	0	0	4,126
WMAAC	4,019	146	43	3	1,624	412	83	23	2,028	8,380
Non-MAAC	6,946	1,665	162	403	2,478	802	4,829	84	34,594	51,963
Total	20,304	3,786	308	406	6,282	4,051	5,833	161	39,656	80,787

Table 3-10 Existing PJM capacity: At June 30, 2011[8] (By zone and unit type (MW)) (See 2010 SOM, Table 3-50)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	0	661	21	0	0	0	1,264	0	8	1,953
AEP	4,367	3,676	59	1,002	2,094	0	21,574	0	1,203	33,976
AP	1,129	1,180	36	80	0	0	8,451	0	691	11,566
ATSI	0	1,661	52	0	2,134	0	8,029	0	0	11,876
BGE	0	835	7	0	1,705	0	3,007	0	0	5,554
ComEd	1,738	7,178	111	0	10,421	0	6,790	0	1,945	28,183
DAY	0	1,369	52	0	0	1	3,572	0	0	4,993
DLCO	244	15	0	6	1,777	0	1,244	0	0	3,286
Dominion	3,173	3,761	161	3,589	3,558	0	8,545	0	0	22,787
DPL	1,125	1,773	96	0	0	0	1,825	0	0	4,819
External	974	1,590	0	66	439	0	9,470	0	185	12,724
JCPL	1,390	1,225	33	400	615	0	318	0	0	3,980
Met-Ed	2,000	406	42	20	805	0	885	0	0	4,157
PECO	2,644	836	7	1,642	4,541	3	1,649	1	0	11,322
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	2,878	2,863	0	5	3,493	34	2,529	0	0	11,802
Total	23,702	31,315	775	7,904	34,051	39	96,190	1	4,806	198,784

7 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.
8 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-11 PJM capacity (MW) by age: at June 30, 2011 (See 2010 SOM, Table 3-51)

Age (years)	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	18,467	16,177	425	11	0	39	1,887	1	4,796	41,802
11 to 20	3,936	6,323	114	48	0	0	5,632	0	10	16,062
21 to 30	857	1,162	37	3,382	16,517	0	7,216	0	0	29,171
31 to 40	244	4,401	43	105	16,053	0	35,467	0	0	56,313
41 to 50	198	3,253	153	2,915	1,482	0	27,353	0	0	35,353
51 to 60	0	0	4	379	0	0	16,409	0	0	16,792
61 to 70	0	0	0	0	0	0	2,078	0	0	2,078
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	23,702	31,315	775	7,904	34,051	39	96,190	1	4,806	198,784

Table 3-12 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[9] (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	2.5%	8,037	23.7%	7,030	14,870	34.8%
	Combustion Turbine	1,375	17.0%	7,358	21.7%	1,975	7,958	18.6%
	Diesel	53	0.7%	157	0.5%	68	171	0.4%
	Hydroelectric	2,042	25.3%	2,047	6.0%	0	5	0.0%
	Nuclear	615	7.6%	8,648	25.5%	540	9,188	21.5%
	Solar	0	0.0%	37	0.1%	2,827	2,864	6.7%
	Steam	3,784	46.9%	7,584	22.4%	790	4,589	10.7%
	Storage	0	0.0%	1	0.0%	54	55	0.1%
	Wind	0	0.0%	8	0.0%	3,034	3,042	7.1%
	EMAAC Total	8,067	100.0%	33,877	100.0%	16,318	42,742	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%
	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%

Table 3-12 continued next page.

9 Percents shown in Table 3-12 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 3-12, 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
WMAAC	Combined Cycle	0	0.0%	3,810	16.1%	4,019	7,829	48.5%
	Combustion Turbine	312	3.8%	1,367	5.8%	146	1,201	7.4%
	Diesel	46	0.6%	129	0.5%	43	126	0.8%
	Hydroelectric	887	10.9%	1,113	4.7%	3	229	1.4%
	Nuclear	0	0.0%	3,275	13.8%	1,624	4,899	30.4%
	Solar	0	0.0%	0	0.0%	412	412	2.6%
	Steam	6,887	84.7%	13,246	55.9%	83	6,441	39.9%
	Storage	0	0.0%	0	0.0%	23	23	0.1%
	Wind	0	0.0%	775	3.3%	2,028	2,803	17.4%
	WMAAC Total	8,132	100.0%	23,715	100.0%	8,380	16,134	100.0%
Non-MAAC	Combined Cycle	0	0.0%	11,624	9.0%	6,946	18,570	12.7%
	Combustion Turbine	805	2.3%	20,429	15.8%	1,665	21,289	14.5%
	Diesel	57	0.2%	470	0.4%	162	575	0.4%
	Hydroelectric	1,429	4.1%	4,744	3.7%	403	3,718	2.5%
	Nuclear	867	2.5%	20,423	15.8%	2,478	22,034	15.0%
	Solar	0	0.0%	1	0.0%	802	803	0.5%
	Steam	31,478	90.9%	67,675	52.3%	4,829	41,026	28.0%
	Storage	0	0.0%	0	0.0%	84	84	0.1%
	Wind	0	0.0%	4,024	3.1%	34,594	38,618	26.3%
	Non-MAAC Total	34,636	100.0%	129,390	100.0%	51,963	146,718	100.0%
All Areas	Total	55,436		198,784		80,787	216,921	

Environmental Impact and Renewables

Characteristics of Wind Units

Table 3-13 Capacity factor[10] of wind units in PJM, January through June 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	30.2%	NA	54,947	849
Capacity Resource	32.3%	207.8%	174,272	3,957
All Units	32.1%	207.8%	229,219	4,806

10 Capacity factor by cleared MW refers to cleared RPM MW in peak periods (peak hours during January, February, June, July, and August).

Table 3-14 Wind resources in real time offering at a negative price in PJM, January through June 2011 (See 2010 SOM, Table 3-54)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	1,062.0	1,466	2.81%
All Wind	2,407.6	2,757	5.29%

Figure 3-1 Average hourly real-time generation of wind units in PJM, January through June 2011 (See 2010 SOM, Figure 3-13)

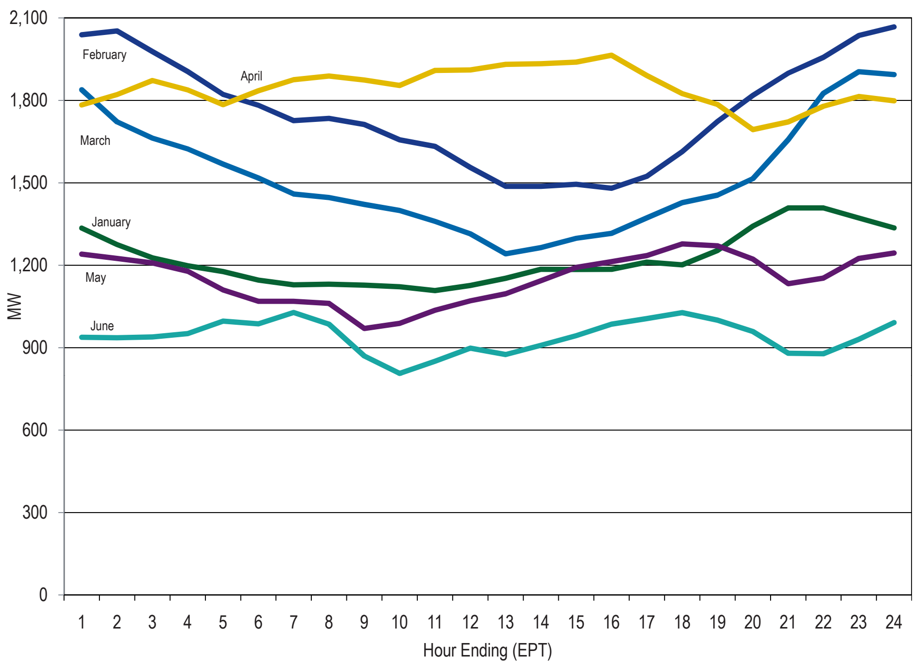


Table 3-15 Capacity factor of wind units in PJM by month, 2010 and 2011[11] (See 2010 SOM, Table 3-55)

	2010		2011	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	818,423.9	35.7%	909,690.8	29.1%
February	612,044.4	28.6%	1,181,192.0	40.5%
March	727,819.1	29.5%	1,130,037.9	35.0%
April	881,317.4	35.5%	1,329,713.7	42.5%
May	670,571.5	26.2%	856,656.7	26.5%
June	472,775.6	18.6%	677,215.5	20.7%
July	380,114.8	14.4%		
August	330,818.7	12.1%		
September	705,289.0	24.0%		
October	1,006,233.1	32.5%		
November	1,088,610.5	35.5%		
December	1,118,789.3	35.3%		
Annual	8,812,807.2	27.4%	6,084,506.5	32.1%

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

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	32.5%	41.0%	23.9%		31.0%
	Average Wind Generation	1,407.3	1,782.5	1,063.1		1,443.6
	Average Load	86,939.1	75,551.5	91,635.1		86,648.4
Off-Peak	Capacity Factor	36.2%	43.8%	23.3%		33.0%
	Average Wind Generation	1,568.1	1,903.1	1,034.1		1,353.3
	Average Load	75,243.8	62,156.7	70,626.9		71,493.0

11 Capacity factor shown in Table 3-15 is based on all hours in January through April, 2011.

Figure 3-2 Average hourly day-ahead generation of wind units in PJM, January through June 2011 (See 2010 SOM, Figure 3-14)

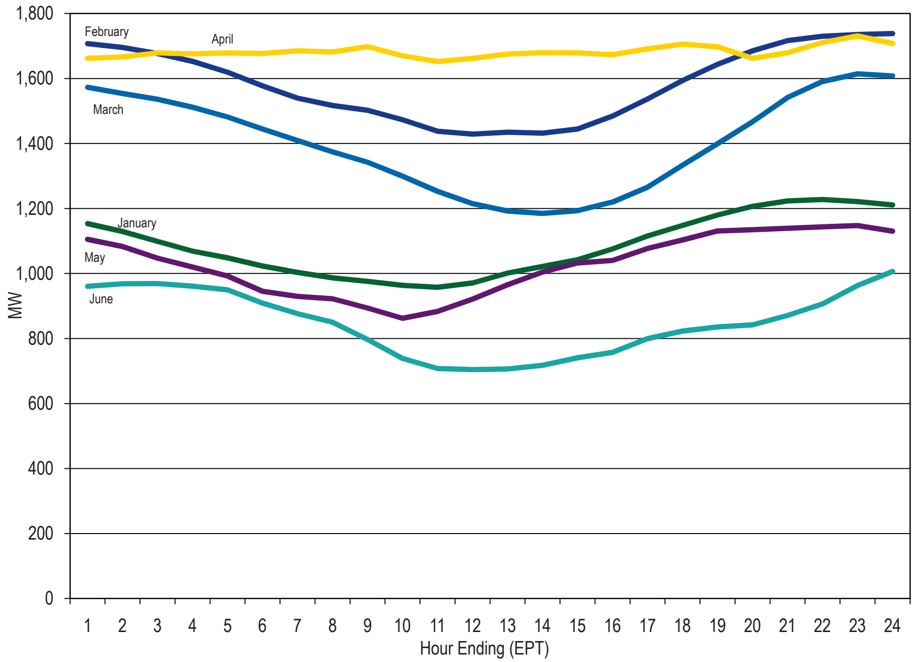
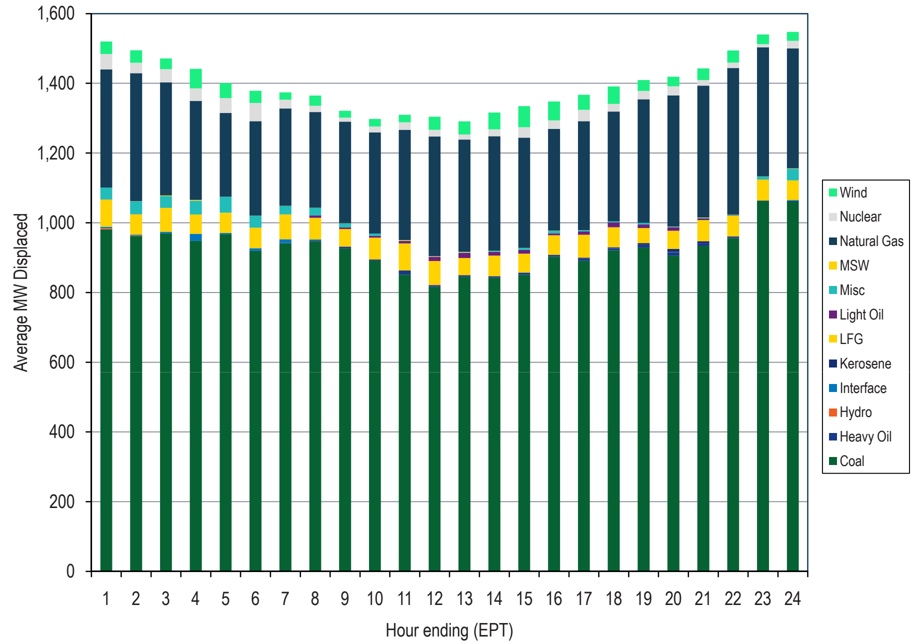


Figure 3-3 Marginal fuel at time of wind generation in PJM, January through June 2011 (See 2010 SOM, Figure 3-15)



Environmental Regulatory Impacts

Emission Allowances Trading

Figure 3-4 Spot monthly average emission price comparison: 2010 and 2011 (See 2010 SOM, Figure 3-16)

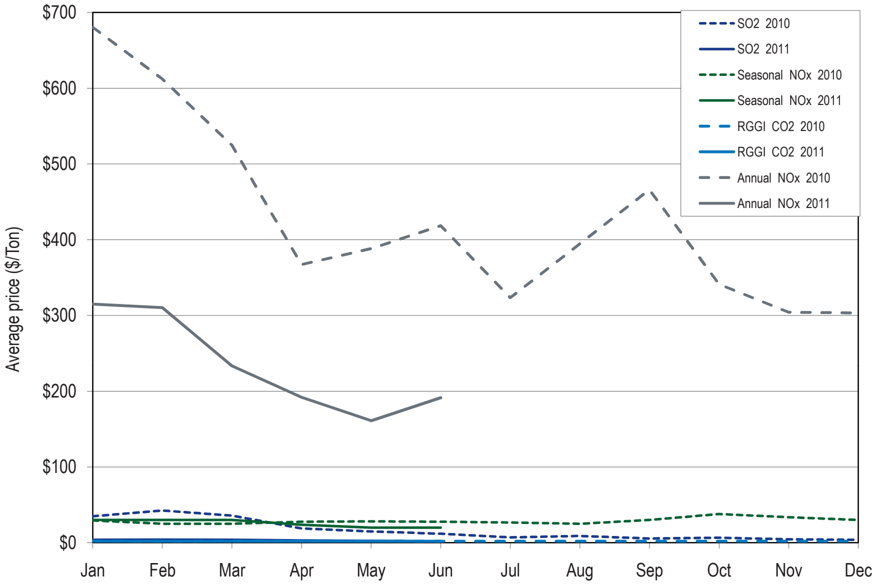


Table 3-17 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2010 SOM, Table 3-57)[12]

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

Emission Controlled Capacity in the PJM Region

Table 3-18 SO_2 emission controls (FGD) by unit type (MW), as of June 30, 2011 (See 2010 SOM, Table 3-58)

	SO2 Controlled	No SO2 Controls	Total	Percent Controlled
Coal Steam	54,741.7	30,117.0	84,858.7	64.5%
Combined Cycle	0.0	23,723.4	23,723.4	0.0%
Combustion Turbine	0.0	30,509.2	30,509.2	0.0%
Diesel	0.0	371.2	371.2	0.0%
Non-Coal Steam	0.0	10,837.0	10,837.0	0.0%
Total	54,741.7	95,557.8	150,299.5	36.4%

Table 3-19 NO_x emission controls by unit type (MW), as of June 30, 2011 (See 2010 SOM, Table 3-59)

	NOx Controlled	No NOx Controls	Total	Percent Controlled
Coal Steam	82,075.9	2,782.8	84,858.7	96.7%
Combined Cycle	23,573.4	150.0	23,723.4	99.4%
Combustion Turbine	24,818.5	5,690.7	30,509.2	81.3%
Diesel	0.0	371.2	371.2	0.0%
Non-Coal Steam	5,808.1	5,028.9	10,837.0	53.6%
Total	136,275.9	14,023.6	150,299.5	90.7%

Table 3-20 Particulate emission controls by unit type (MW), as of June 30, 2011 (See 2010 SOM, Table 3-60)

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	83,099.7	1,759.0	84,858.7	97.9%
Combined Cycle	0.0	23,723.4	23,723.4	0.0%
Combustion Turbine	0.0	30,509.2	30,509.2	0.0%
Diesel	0.0	371.2	371.2	0.0%
Non-Coal Steam	3,047.0	7,790.0	10,837.0	28.1%
Total	86,146.7	64,152.8	150,299.5	57.3%

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

Renewable Portfolio Standards

Table 3-21 Renewable standards of PJM jurisdictions to 2021[13,14] (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%

Table 3-22 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										

13 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

14 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 3-23 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 3-24 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 3-25 Renewable generation by jurisdiction and renewable resource type (GWh): January through June 2011 (See 2010 SOM, Table 3-65)

Jurisdiction	Battery	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	0.0	29.9	0.0	0.0	0.0	0.0	0.0	0.0	29.9	59.7
Indiana	0.0	0.0	0.0	24.4	0.0	0.0	0.0	1,525.5	1,549.9	1,549.9
Illinois	0.0	74.9	0.0	0.0	0.0	3.2	0.0	2,819.4	2,894.2	2,897.4
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	42.9	0.0	1,369.4	0.0	292.3	0.0	166.1	1,578.3	1,870.6
Michigan	0.0	14.2	0.0	33.5	0.0	0.0	0.0	0.0	47.7	47.7
New Jersey	0.0	140.1	275.5	17.6	19.2	674.8	0.0	5.9	182.7	1,133.1
North Carolina	0.0	0.0	0.0	231.2	0.0	0.0	0.0	0.0	231.2	231.2
Ohio	0.0	27.6	0.0	50.3	0.6	0.0	0.0	3.6	82.2	82.2
Pennsylvania	0.1	424.7	851.8	1,598.7	1.9	1,113.5	4,992.7	1,007.7	3,033.0	9,991.1
Tennessee	0.0	0.0	0.0	0.0	0.0	172.5	0.0	0.0	0.0	172.5
Virginia	0.0	85.4	2,263.5	428.7	0.0	596.2	0.0	0.0	514.2	3,373.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.9	0.0	582.2	0.0	0.0	552.9	556.4	1,139.5	1,692.4
Total	0.1	840.5	3,390.8	4,336.1	21.6	2,852.6	5,545.6	6,084.5	11,282.7	23,071.8

Table 3-26 PJM renewable capacity by jurisdiction (MW), on June 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	60.0	24.5	129.0	97.9	0.0	1,162.0	0.0	109.0	0.0	120.0	1,702.4
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	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
North Carolina	0.0	80.4	0.0	0.0	400.0	5.0	34.5	191.1	0.0	7.5	718.5
Ohio	3,339.7	25.8	25.0	27.2	0.0	112.0	1.1	0.0	0.0	150.0	3,680.8
Pennsylvania	35.0	215.5	2,370.7	0.0	2,575.0	672.6	3.0	263.0	1,418.9	790.0	8,343.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	108.5	80.0	16.9	3,588.0	457.1	0.0	215.0	0.0	0.0	4,465.5
West Virginia	500.0	2.0	0.0	0.0	0.0	239.6	0.0	0.0	130.0	555.5	1,427.1
PJM Total	3,934.7	534.5	4,440.0	157.0	6,563.0	2,983.3	38.6	943.1	1,548.9	4,806.1	25,949.2

Table 3-27 Renewable capacity by jurisdiction, non-PJM units registered in GATS[15,16] (MW), on June 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	9.3	0.0	0.1	9.4
Illinois	4.0	97.8	0.0	0.0	0.0	10.6	0.0	302.5	414.9
Indiana	0.0	26.4	0.0	679.1	0.0	0.4	0.0	0.0	705.9
Kentucky	2.0	16.0	0.0	0.0	0.0	0.2	88.0	0.0	106.3
Maryland	0.0	5.0	0.0	0.0	0.0	21.4	0.0	0.0	26.4
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	225.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	227.3
New York	0.0	36.5	0.0	0.0	23.3	293.3	0.0	0.2	353.2
North Carolina	179.9	0.0	0.0	0.0	0.0	0.4	0.0	0.0	180.4
Ohio	1.0	49.5	52.6	45.0	0.0	23.1	109.3	9.7	290.2
Pennsylvania	0.2	5.4	4.8	85.5	0.3	80.0	0.0	3.2	179.4
Virginia	12.5	14.8	0.0	0.0	0.0	4.7	318.1	0.0	350.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	1.9
West Virginia	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.3
Wisconsin	9.0	0.0	0.0	0.0	0.0	0.6	44.6	0.0	54.2
Total	433.7	253.0	57.4	809.6	23.6	448.8	560.0	461.8	3,047.9

15 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.
16 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed July 01, 2011).

Operating Reserve[17]

Credit and Charge Results

Overall Results

Table 3-28 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	$47,862,223	$60,345,417
Feb	$11,425,494	$14,715	$22,346,529	$33,786,738	$8,940,203	$139,287	$26,361,087	$35,440,577
Mar	$8,836,886	$122,817	$16,823,288	$25,782,991	$6,837,719	$66,032	$24,219,868	$31,123,619
Apr	$7,633,141	$93,253	$22,870,495	$30,596,889	$4,405,102	$13,011	$18,453,276	$22,871,388
May	$5,127,307	$131,600	$39,144,404	$44,403,311	$7,064,934	$39,417	$44,579,042	$51,683,393
Jun	$3,511,264	$33,923	$56,989,229	$60,534,415	$8,303,391	$9,056	$60,957,566	$69,270,014
Jul	$4,601,788	$88,136	$63,190,853	$67,880,778				
Aug	$3,622,670	$66,535	$41,690,612	$45,379,817				
Sep	$8,433,892	$27,971	$40,637,086	$49,098,949				
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	$46,815,443	$446,330	$198,646,441	$245,908,215	$47,924,448	$376,898	$222,433,063	$270,734,409
Share of Annual Charges	19.0%	0.2%	80.8%	100.0%	17.7%	0.1%	82.2%	100.0%

17 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 3-29 Regional balancing operating reserve charges allocation: January through June 2011[18] (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	$28,732,141 20.3%	$1,159,813 0.8%	$29,891,954 21.2%	$51,525,893 36.5%	$16,397,206 11.6%	$17,921,911 12.7%	$85,845,010 60.7%	$115,736,964 81.9%
East	$2,987,646 2.1%	$93,096 0.1%	$3,080,743 2.2%	$5,636,070 4.0%	$1,462,329 1.0%	$1,477,305 1.0%	$8,575,704 6.1%	$11,656,447 8.2%
West	$10,703,266 7.6%	$554,465 0.4%	$11,257,730 8.0%	$1,436,871 1.0%	$609,733 0.4%	$625,431 0.4%	$2,672,035 1.9%	$13,929,766 9.9%
Total	$42,423,052 30.0%	$1,807,375 1.3%	$44,230,427 31.3%	$58,598,834 41.5%	$18,469,268 13.1%	$20,024,647 14.2%	$97,092,749 68.7%	$141,323,176 100%

Deviations

Allocation

Table 3-30 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	9,795,075	3,263,461	3,189,885	16,248,420
Feb	7,675,656	5,332,236	2,456,048	15,463,940	7,196,554	2,809,384	2,712,419	12,718,358
Mar	8,101,950	5,138,264	2,264,951	15,505,165	7,510,358	2,467,175	2,777,797	12,755,330
Apr	7,006,983	4,668,407	2,132,045	13,807,435	6,622,271	2,027,200	2,714,483	11,363,954
May	9,004,034	4,228,004	2,416,103	15,648,141	7,148,336	2,381,985	2,930,319	12,460,640
Jun	10,936,989	3,964,478	3,174,230	18,075,697	9,846,329	2,558,367	3,035,163	15,439,859
Jul	10,928,408	3,847,011	3,412,498	18,187,917				
Aug	9,747,045	3,417,328	3,188,437	16,352,810				
Sep	9,480,237	3,587,356	2,524,213	15,591,806				
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	48,118,923	15,507,572	17,360,066	80,986,561
Share of Annual Deviations	56.6%	26.2%	17.2%	100.0%	59.4%	19.1%	21.4%	100.0%

18 The total charges shown in Table 3-29 do not equal the total balancing charges shown in Table 3-28 because the totals in Table 3-28 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-29 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 3-31 Regional operating reserve charges determinants (MWh): January through June 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	342,314,644	14,602,809	356,917,452	48,118,923	15,507,572	17,360,066	80,986,561	437,904,013
East	182,993,605	6,816,309	189,809,914	29,066,619	8,324,158	8,469,894	45,860,671	235,670,585
West	159,321,038	7,786,500	167,107,538	18,883,992	7,093,775	8,718,421	34,696,188	201,803,727

Table 3-32 Monthly impacts on netting deviations: January through June 2011 (See SOM 2010, Table 3-76)

Month	Demand Deviations (MWh) Old Rules	Demand Deviations (MWh) New Rules	Difference	Supply Deviations (MWh) Old Rules	Supply Deviations (MWh) New Rules	Difference	Generator Deviations (MWh) Old Rules	Generator Deviations (MWh) New Rules	Difference
Jan	8,956,331	9,795,075	838,743	3,137,527	3,263,461	125,934	3,197,210	3,190,656	(6,554)
Feb	6,694,980	7,196,554	501,574	2,738,472	2,809,384	70,912	2,727,242	2,712,446	(14,796)
Mar	7,007,409	7,510,358	502,950	2,386,348	2,467,172	80,824	2,787,110	2,777,995	(9,115)
Apr	6,114,800	6,622,271	507,471	1,974,093	2,027,200	53,106	2,719,625	2,714,483	(5,142)
May	6,682,928	7,148,336	465,407	2,342,384	2,381,985	39,601	2,945,222	2,939,608	(5,614)
Jun	8,916,182	9,846,329	930,147	2,580,099	2,558,367	(21,733)	3,067,764	3,034,875	(32,888)
Total	44,372,631	48,118,923	3,746,293	15,158,924	15,507,569	348,645	17,444,173	17,370,063	(74,109)

Table 3-33 Summary of impact on netting deviations: January through June 2011 (See SOM 2010, Table 3-77)

	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Total Deviations (MWh)
Old Rules (No Netting)	44,372,631	15,158,924	17,444,173	76,975,727
New Rules (Netting)	48,118,923	15,507,569	17,370,063	80,996,555
Difference	3,746,293	348,645	(74,109)	4,020,828

Balancing Operating Reserve Charge Rate

Figure 3-5 Daily RTO reliability and deviation balancing operating reserve rates ($/MWh): January through June 2011 (See SOM 2010, Figure 3-20)

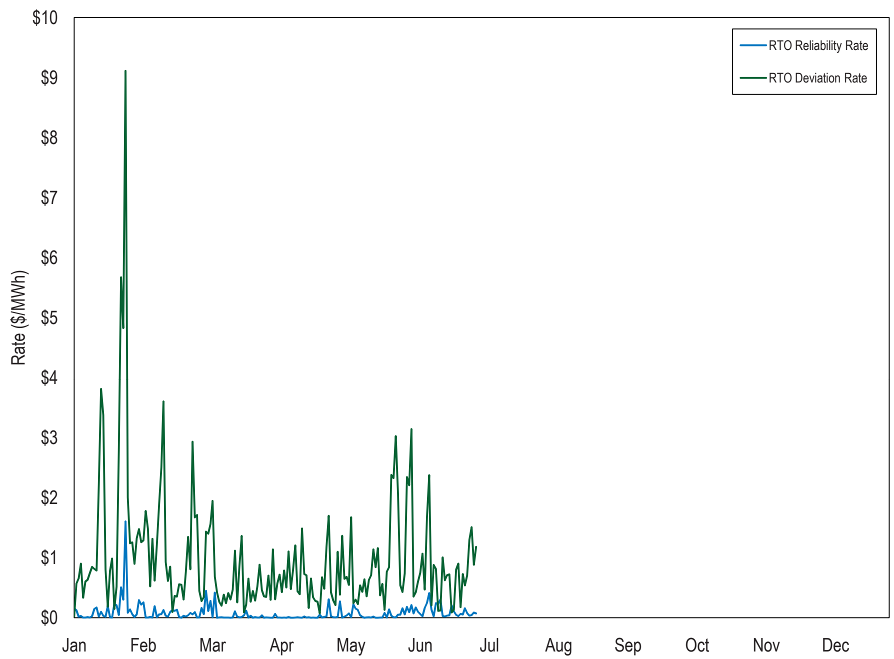


Figure 3-6 Daily regional reliability and deviation rates ($/MWh): January through June 2011 (See SOM 2010, Figure 3-21)

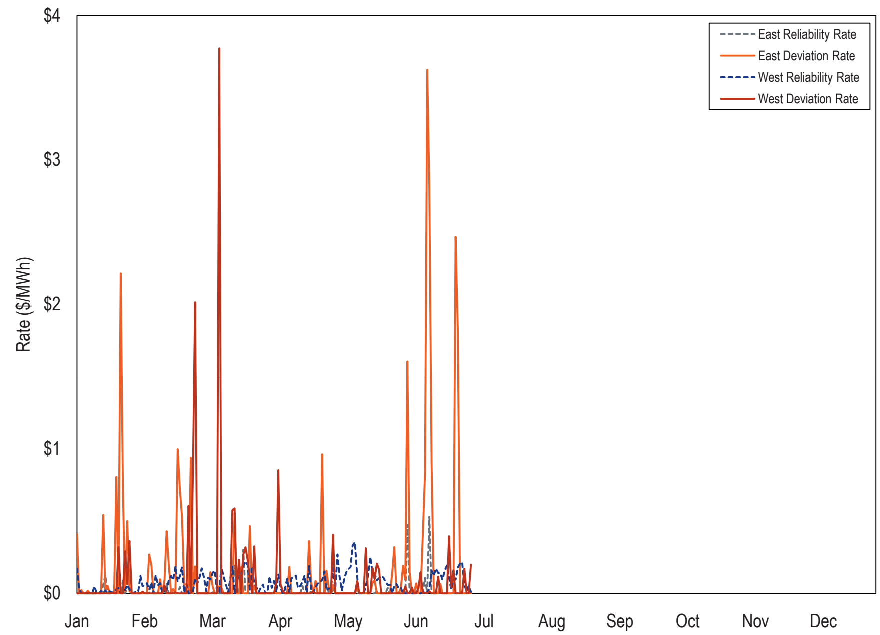


Table 3-34 Regional balancing operating reserve rates ($/MWh): January through June 2011 (See SOM 2010, Table 3-78)

	Reliability ($/MWh)	Deviations ($/MWh)
RTO	0.015	0.162
East	0.033	0.082
West	0.980	0.000

Operating Reserve Credits by Category

Figure 3-7 Operating reserve credits: January through June 2011 (See SOM 2010, Figure 3-22)

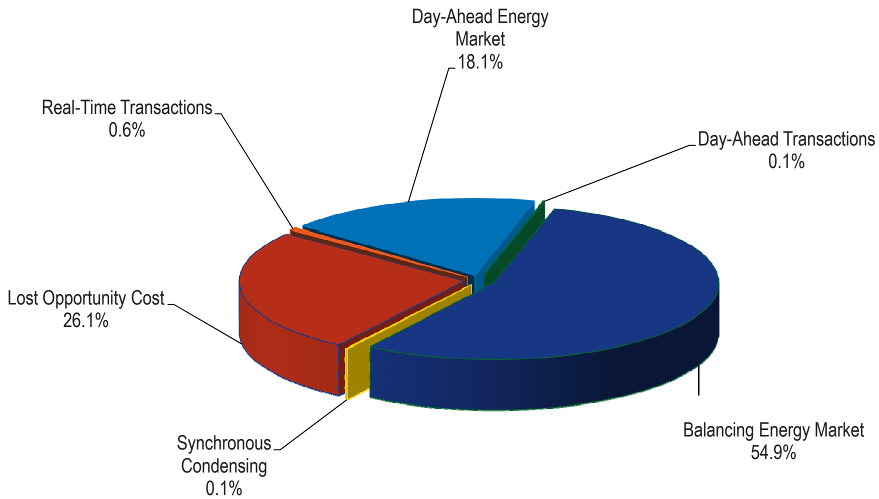


Table 3-35 Credits by month (By operating reserve market): Calendar year 2011[19] (See SOM 2010, Table 3-79)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$12,352,611	$20,488	$110,095	$42,162,945	$473,317	$2,940,640	$58,060,095
Feb	$8,844,162	$96,041	$139,287	$22,796,574	$378,056	$3,186,458	$35,440,578
Mar	$6,830,696	$7,024	$66,032	$15,720,534	$421,862	$7,085,716	$30,131,863
Apr	$4,395,461	$9,641	$13,011	$11,007,237	$215,816	$7,230,224	$22,871,389
May	$7,057,377	$7,557	$39,417	$21,636,684	$13,365	$20,245,034	$48,999,434
Jun	$8,158,879	$144,512	$9,056	$30,752,084	$20,077	$27,948,556	$67,033,165
Total	$47,639,185	$285,263	$376,898	$144,076,058	$1,522,493	$68,636,627	$262,536,524
Share of Credits	18.1%	0.1%	0.1%	54.9%	0.6%	26.1%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-36 Operating reserve credits by unit types (By operating reserve market): January through June 2011 (See SOM 2010, Table 3-80)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	31.1%	0.0%	66.9%	2.0%	$75,656,593
Combustion Turbine	1.1%	0.4%	45.5%	52.9%	$92,057,522
Diesel	3.3%	0.0%	72.8%	23.9%	$175,429
Hydro	13.0%	0.0%	87.0%	0.0%	$930,452
Landfill	0.0%	0.0%	0.0%	100.0%	$11,033,044
Nuclear	0.0%	0.0%	0.0%	100.0%	$289,427
Steam	29.9%	0.0%	63.3%	6.8%	$75,980,516
Wind Farm	0.0%	0.0%	99.6%	0.4%	$1,808,379

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

Table 3-37 Operating reserve credits by operating reserve market (By unit type): January through June 2011 (See SOM 2010, Table 3-81)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	49.6%	0.0%	35.3%	2.2%
Combustion Turbine	2.2%	100.0%	29.2%	73.0%
Diesel	0.0%	0.0%	0.1%	0.1%
Hydro	0.3%	0.0%	0.6%	0.0%
Landfill	0.0%	0.0%	0.0%	16.5%
Nuclear	0.0%	0.0%	0.0%	0.4%
Steam	48.0%	0.0%	33.5%	7.7%
Wind Farm	0.0%	0.0%	1.3%	0.0%
Total	$47,421,160	$376,898	$143,393,719	$66,739,586

Economic and Noneconomic Generation

Table 3-38 Economic vs. noneconomic hours: January through June 2011 (See SOM 2010, Table 3-82)

Unit Type	Economic Hours	Economic Hours Percentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Combined Cycle	10,458	62.2%	6,363	37.8%	16,821
Combustion Turbine	3,674	34.0%	7,125	66.0%	10,799
Diesel	117	25.6%	340	74.4%	457
Steam	26,550	79.9%	6,668	20.1%	33,218

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-39 Regional balancing operating reserve credits: January through June 2011 (See SOM 2010, Table 3-86)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$29,891,954	$85,845,010	$115,736,964
East	$3,080,743	$8,575,704	$11,656,447
West	$11,257,730	$2,672,035	$13,929,766
Total	$44,230,427	$97,092,749	$141,323,176

Table 3-40 Total deviations: January through June 2011 (See SOM 2010, Table 3-87)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	48,118,923	15,507,572	17,360,066	80,986,561

Table 3-41 Charge allocation under old operating reserve construct: January through June 2011 (See SOM 2010, Table 3-88)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	48,118,923	15,507,572	17,360,066	80,986,561
Balancing Rate ($/MWh)	1.745	1.745	1.745	1.745
Charges ($)	$83,968,488	$27,061,024	$30,293,664	$141,323,176

Table 3-42 Actual regional credits, charges, rates and charge allocation (MWh): January through June 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	$29,891,954	356,917,452	0.084	$29,891,954	$85,845,010	80,986,561	1.060	$85,845,010	$115,736,964
East	$3,080,743	189,809,914	0.016	$3,080,743	$8,575,704	45,860,671	0.187	$8,575,704	$11,656,447
West	$11,257,730	167,107,538	0.067	$11,257,730	$2,672,035	34,696,188	0.077	$2,672,035	$13,929,766
Total	$44,230,427	356,917,452	NA	$44,230,427	$97,092,749	80,986,561	NA	$97,092,749	$141,323,176

Table 3-43 Difference in total operating reserve charges between old rules and new rules: January through June 2011 (See SOM 2010, Table 3-90)

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$83,968,488	$27,061,024	$30,293,664	$141,323,176
Charges (Current)	$42,423,052	$1,807,375	$44,230,427	$58,598,834	$18,469,268	$20,024,647	$97,092,749
Difference	$42,423,052	$1,807,375	$44,230,427	($25,369,654)	($8,591,757)	($10,269,017)	($44,230,427)

Impact on Decrement Bids and Incremental Offers

Table 3-44 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): 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	1,152,806	2,548,787
Apr	7,568,471	9,989,951	2,214,314	2,066,270	5,200,154	7,351,597	956,132	2,049,879
May	8,306,597	11,573,314	2,250,271	3,437,786	5,537,880	7,609,897	1,105,325	2,148,071
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				
Aug	7,862,123	11,648,289	1,465,333	2,676,901				
Sep	8,188,967	11,532,284	2,103,152	3,105,498				
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	34,263,725	47,377,915	7,339,801	14,890,148

Table 3-45 Comparison of balancing operating reserve charges to virtual bids: Calendar years, 2010 and 2011 (See SOM 2010, Table 3-92)

	2010			2011		
Month	Charges Under Old Rules	Charges Under Current Rules	Difference	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,525,384	$10,190,867	($2,334,517)	$13,891,398	$10,165,699	($3,725,698)
Feb	$5,319,874	$3,936,420	($1,383,454)	$7,483,306	$5,767,494	($1,715,812)
Mar	$4,797,076	$3,468,829	($1,328,248)	$6,669,083	$4,947,154	($1,721,929)
Apr	$6,480,725	$5,301,308	($1,179,417)	$4,942,221	$4,056,663	($885,558)
May	$13,658,944	$10,158,307	($3,500,637)	$11,228,667	$9,896,693	($1,331,974)
Jun	$18,021,960	$10,673,612	($7,348,348)	$14,781,112	$11,756,752	($3,024,360)
Jul	$17,068,724	$14,327,987	($2,740,737)			
Aug	$9,394,993	$7,575,980	($1,819,013)			
Sep	$13,065,704	$10,820,010	($2,245,694)			
Oct	$9,019,721	$6,456,368	($2,563,353)			
Nov	$5,817,780	$3,925,450	($1,892,330)			
Dec	$17,570,579	$19,884,462	$2,313,884			
Total	$132,741,464	$106,719,600	($26,021,864)	$58,995,787	$46,590,455	($12,405,332)

Table 3-46 Summary of impact on virtual bids under balancing operating reserve allocation: January through June, 2010 and 2011 (See SOM 2010, Table 3-93)

Jan - Jun	Region	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Adjusted Virtual Deviations (MWh)	Balancing Rate Under Current Rules ($/MWh)	Balancing Rate Under Old Rules ($/MWh)	Charges Under Current Rules	Charges Under Old Rules	Differerence
2010	RTO	13,306,701	17,843,017	31,149,718	1.868	1.194	$61,402,213	$39,270,576	($22,131,638)
	East	8,947,802	11,120,832	20,068,635	0.000	0.113	$0	$1,181,245	$2,843,731
	West	4,309,184	6,577,952	10,887,136	0.000	0.000	$0	$0	$1,181,245
2011	RTO	7,339,801	14,890,148	22,229,949	1.836	2.498	$43,709,241	$58,995,787	($15,286,545)
	East	3,840,936	7,470,872	11,311,807	0.175	0.000	$2,027,106	$0	$2,027,106
	West	3,409,227	7,250,964	10,660,191	0.078	0.000	$854,107	$0	$854,107

Segmented Make Whole Payments

Table 3-47 Impact of segmented make whole payments: Calendar years, 2010 and 2011 (See SOM 2010, Table 3-94)

	2010			2011		
Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
Jan	$32,982,105	$33,924,489	$942,385	$40,766,342	$41,957,597	$1,191,255
Feb	$17,321,317	$17,609,133	$287,815	$21,621,511	$22,774,422	$1,152,911
Mar	$13,458,120	$13,672,172	$214,052	$14,872,573	$15,695,526	$822,954
Apr	$16,441,644	$17,036,058	$594,414	$10,202,172	$10,884,948	$682,776
May	$21,854,306	$23,455,721	$1,601,415	$18,606,188	$20,402,476	$1,796,288
Jun	$36,297,521	$38,885,349	$2,587,828	$27,575,556	$31,046,441	$3,470,886
Jul	$32,251,623	$37,053,630	$4,802,007			
Aug	$21,867,024	$24,335,171	$2,468,147			
Sep	$24,293,196	$25,686,790	$1,393,593			
Oct	$21,839,101	$22,478,455	$639,354			
Nov	$15,795,391	$16,238,383	$442,991			
Dec	$49,180,164	$51,293,810	$2,113,646			
Total	$303,581,512	$321,669,160	$18,087,648	$133,644,341	$142,761,411	$9,117,069

Table 3-48 Share of balancing operating reserve increases for segmented make whole payments (By unit type): January through June 2011 (See SOM 2010, Table 3-96)

Unit Type	Share of Increase
Combined-Cycle	48.6%
Combustion Turbines	33.2%
Steam	18.1%
Diesel	0.1%

Unit Operating Parameters[20]

Table 3-49 Units receiving credits from a parameter limited schedule: January through June 2011 (See SOM 2010, Table 3-98)

Unit Type	Number of Units	Observations
Combined-Cycle	1	4
Large Frame Combustion Turbine (135 - 180 MW)	5	11
Medium-Large Frame Combustion Turbine (65 - 125 MW)	9	44
Petroleum/Gas Steam (Pre-1985)	2	2
Sub-Critical Coal	20	107

Issues in Operating Reserves

Concentration of Operating Reserve Credits

Table 3-50 Unit operating reserve credits (By zone): January through June 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	$274,894	$0	$2,199,633	$2,007,460	$4,481,987	1.7%
AEP	$1,235,203	$368	$22,906,738	$4,944,754	$29,087,062	11.2%
AP	$893,398	$0	$4,852,097	$3,901,669	$9,647,164	3.7%
ATSI	$205,519	$0	$193,350	$1,894,992	$2,293,862	0.9%
BGE	$4,967,552	$0	$3,944,432	$361,172	$9,273,156	3.6%
ComEd	$425,869	$0	$2,291,135	$7,802,345	$10,519,348	4.0%
DAY	$78,783	$0	$437,577	$130,359	$646,719	0.2%
Dominion	$2,838,549	$0	$23,431,639	$38,150,077	$64,420,264	24.7%
DLCO	$161,831	$0	$1,110,820	$5,239	$1,277,890	0.5%
DPL	$727,090	$0	$6,908,735	$749,387	$8,385,213	3.2%
JCPL	$1,355,222	$0	$4,431,998	$625,010	$6,412,229	2.5%
Met-Ed	$120,577	$0	$1,404,692	$337,577	$1,862,846	0.7%
PECO	$607,154	$4,692	$3,906,967	$1,412,073	$5,930,885	2.3%
PENELEC	$295,112	$0	$1,501,303	$318,057	$2,114,472	0.8%
Pepco	$2,160,314	$0	$11,440,864	$3,662,251	$17,263,430	6.6%
PPL	$362,546	$0	$4,769,857	$959,946	$6,092,349	2.3%
PSEG	$30,929,572	$371,838	$48,344,221	$1,374,261	$81,019,892	31.1%
External	$0	$0	$0	$0	$0	0.0%
Total	$47,639,185	$376,898	$144,076,058	$68,636,627	$260,728,769	100.0%

20 See the *2010 State of the Market Report for PJM*, Volume 2, Section 3, "Energy Market, Part 2," Table 3-97 *Unit Parameter Limited Schedule Matrix* for details regarding default unit operating parameters.

Table 3-51 Top 10 units and organizations receiving total operating reserve credits: January through June 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	$25,079,394	9.6%	9.6%	$80,499,792	30.9%	30.9%
2	$20,266,194	7.8%	17.4%	$48,591,684	18.6%	49.5%
3	$14,737,524	5.7%	23.0%	$19,347,376	7.4%	56.9%
4	$6,152,848	2.4%	25.4%	$11,936,834	4.6%	61.5%
5	$5,105,132	2.0%	27.4%	$11,013,317	4.2%	65.7%
6	$4,459,407	1.7%	29.1%	$10,594,807	4.1%	69.8%
7	$3,722,211	1.4%	30.5%	$7,490,078	2.9%	72.7%
8	$3,459,683	1.3%	31.8%	$6,687,352	2.6%	75.2%
9	$3,287,786	1.3%	33.1%	$5,745,703	2.2%	77.4%
10	$3,218,698	1.2%	34.3%	$5,745,477	2.2%	79.6%

Table 3-52 Top 10 units and organizations receiving day-ahead generator credits: January through June 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	$11,590,529	24.3%	24.3%	$30,810,681	64.7%	64.7%
2	$9,677,411	20.3%	44.6%	$5,049,931	10.6%	75.3%
3	$5,381,825	11.3%	55.9%	$2,772,387	5.8%	81.1%
4	$2,059,315	4.3%	60.3%	$1,824,719	3.8%	84.9%
5	$1,937,566	4.1%	64.3%	$1,095,566	2.3%	87.2%
6	$1,776,698	3.7%	68.1%	$976,591	2.0%	89.3%
7	$1,459,626	3.1%	71.1%	$649,814	1.4%	90.6%
8	$1,095,566	2.3%	73.4%	$551,011	1.2%	91.8%
9	$455,192	1.0%	74.4%	$519,792	1.1%	92.9%
10	$382,258	0.8%	75.2%	$468,225	1.0%	93.9%

Table 3-53 Top 10 units and organizations receiving synchronous condensing credits: January through June 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	$35,887	9.5%	9.5%	$371,838	98.7%	98.7%
2	$33,192	8.8%	18.3%	$4,692	1.2%	99.9%
3	$31,995	8.5%	26.8%	$368	0.1%	100.0%
4	$31,793	8.4%	35.3%			
5	$25,729	6.8%	42.1%			
6	$23,986	6.4%	48.4%			
7	$23,039	6.1%	54.6%			
8	$15,433	4.1%	58.7%			
9	$13,620	3.6%	62.3%			
10	$13,089	3.5%	65.7%			

Table 3-54 Top 10 units and organizations receiving balancing generator credits: January through June 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	$19,685,413	13.7%	13.7%	$47,943,012	33.3%	33.3%
2	$8,653,852	6.0%	19.7%	$20,074,030	13.9%	47.2%
3	$5,056,441	3.5%	23.2%	$15,690,653	10.9%	58.1%
4	$4,649,940	3.2%	26.4%	$10,477,906	7.3%	65.4%
5	$4,091,759	2.8%	29.2%	$5,395,108	3.7%	69.1%
6	$3,197,086	2.2%	31.5%	$4,917,553	3.4%	72.5%
7	$2,997,047	2.1%	33.5%	$4,682,426	3.2%	75.8%
8	$2,526,301	1.8%	35.3%	$3,893,635	2.7%	78.5%
9	$2,469,064	1.7%	37.0%	$3,516,216	2.4%	80.9%
10	$2,208,298	1.5%	38.5%	$3,109,125	2.2%	83.1%

Table 3-55 Top 10 units and organizations receiving lost opportunity cost credits: January through June 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	$3,708,849	5.4%	5.4%	$25,745,266	37.5%	37.5%
2	$3,442,108	5.0%	10.4%	$10,555,653	15.4%	52.9%
3	$2,322,305	3.4%	13.8%	$3,442,108	5.0%	57.9%
4	$2,053,327	3.0%	16.8%	$3,359,135	4.9%	62.8%
5	$2,041,305	3.0%	19.8%	$2,998,092	4.4%	67.2%
6	$1,865,391	2.7%	22.5%	$2,733,470	4.0%	71.1%
7	$1,787,465	2.6%	25.1%	$2,680,133	3.9%	75.1%
8	$1,705,513	2.5%	27.6%	$1,700,722	2.5%	77.5%
9	$1,641,311	2.4%	30.0%	$1,374,261	2.0%	79.5%
10	$1,567,090	2.3%	32.2%	$1,286,619	1.9%	81.4%

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.

Table 3-56 is based on calculating notification and startup times independently, then adding together. Table 3-57 is based on adding notification and startup times together first, then calculating distribution. All data are based on historical cost-based offers within one standard deviation of the mean since November 2007.

Table 3-56 Cold notification and cold startup hours (By percentile): Since November 2007 (New table)

	Cold Notification Time			Cold Startup Time			CS + CN		
Parameter Class	70th	80th	90th	70th	80th	90th	70th	80th	90th
Petroleum/Gas Steam (Pre-1985)	4	8.5	18	12.5	14	18	16.5	22.5	36
Petroleum/Gas Steam (Post-1985)	1	1	2	6	12	14	7	13	16
Combined-Cycle	2	5	7	5	6.2	8	7	11.2	15
Sub-Critical Coal	2	2	4	15	16	20	17	18	24
Super-Critical Coal	2	2	8	19	20	22	21	22	30
Small Frame Combustion Turbine (0 - 30 MW)	0.25	1	2	0.5	0.5	0.8	0.75	1.5	2.8
Medium Frame Combustion Turbine (30 - 65 MW)	0.2	0.3	1.4	0.3	0.5	0.5	0.5	0.8	1.9
Medium-Large Frame Combustion Turbine (65 - 135 MW)	1	2	2	0.5	0.7	1	1.5	2.7	3
Large Frame Combustion Turbine (135 - 180 MW)	2	5	6	0.5	0.7	1	2.5	5.7	7

Table 3-57 Time-To-Start hours (By percentile): Since November 2007 (New table)

	All Months			Peak Months			Off-Peak Months		
Parameter Class	70th	80th	90th	70th	80th	90th	70th	80th	90th
Petroleum/Gas Steam (Pre-1985)	18	20	32	18	20	30	17	19	32
Petroleum/Gas Steam (Post-1985)	9	13	14	9	13	14	9	13	14
Combined-Cycle	9	11	14	8.5	10	13.5	9	11	14
Sub-Critical Coal	16.5	18	22	16.5	18	22.5	16	18	22
Super-Critical Coal	21	22	30	21	22	30	21	22	30
Small Frame Combustion Turbine (0 - 30 MW)	1	1.5	2.2	1	1.5	2.2	1	1.5	2.2
Medium Frame Combustion Turbine (30 - 65 MW)	0.5	0.8	1.7	0.5	0.7	1.7	0.5	1	2
Medium-Large Frame Combustion Turbine (65 - 135 MW)	2	2	3.3	2	2	3.3	2	2.3	3.4
Large Frame Combustion Turbine (135 - 180 MW)	3	5	6.6	2.5	4.3	6.6	4	5	6.8

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. For example, a unit may temporarily extend a minimum down time parameter to avoid being turned off when not economic, and not based on a physical change at the unit. This will increase operating reserve credits to the unit and operating reserve charges paid by other participants. As another example, a unit may offer more flexible operating parameters on a price-based schedule than on a cost-based schedule. The result is higher market prices when the price-based schedule is taken in place of the cost-based schedule when offer capping is implemented and the potential for increased operating reserve credits to the unit and operating reserve charges paid by other participants when the cost-based schedule is used. The MMU recommends that the PJM dispatch become more forward looking in order to better capture the operation of baseload units that were not designed to cycle daily and that the most flexible parameter offered be used as the parameter limited schedule.

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, American Transmission Systems, Inc. (ATSI) integrated into PJM. The affect of this integration on interchange transactions was the elimination of the First Energy (FE) Interface as well as the elimination of the MICHFE Interface Pricing Point.

- Real-time net exports decreased to -2949.1 GWh during the first six months of 2011 from -3,356.4 GWh during the first six months of 2010. During the first six months of 2011, there were day-ahead net imports of 10,914.7 GWh compared to net exports of -5,489.5 GWh during the first six months of 2010.

- 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 in 59 percent of hours between PJM and MISO and in 47 percent of hours between PJM and NYISO during the first six months of 2011.

- During the first six months of 2011, net scheduled interchange was -1,623 GWh and net actual interchange was -1,876 GWh for a difference of 253 GWh or 15.6 percent (7.7 percent during the first six months of 2010 and 5.2 percent for the calendar year 2010). This difference is system inadvertent.

- PJM initiated fewer TLRs during the first six months of 2011 than during the first six months of 2010 (40 TLRs during the first six months of 2011 compared to 58 TLRs during the first six 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 1,634 bids per day for the period between September 17, 2010 through June 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 six months of 2011 were $10,790, compared to $1.2 million for the first six 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 six months of 2011, an increase from $290,515 in the first six months of 2010.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through June*, 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. integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduces 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 six months of 2011, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter 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 to PJM.

in the remaining months. During the first six 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 -491 GWh compared to -559 GWh for the first six months of 2010.[2] Gross monthly import volumes averaged 3,464 GWh compared to 3,509 GWh for the first six months of 2010 while gross monthly exports averaged 3,955 GWh compared to 4,068 GWh for the first six months of 2010.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first six months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in all months. During the first six months of 2010, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. In the Day-Ahead Energy Market, monthly net interchange averaged 1,819 GWh compared to -915 GWh for the first six months of 2010. Gross monthly import volumes averaged 9,801 GWh compared to 5,716 GWh for the first six months of 2010 while gross monthly exports averaged 7,982 GWh compared to 6,631 GWh for the first six months of 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first six months of 2011 was the significant increase in up-to congestion transactions. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 1,258 bids per day (with an average cleared volume of 427,215 MWh per day) during the first six months of 2011, compared to an average of 379 bids per day (with an average cleared volume of 237,579 MWh per day) during the first six months of 2010. (See Figure 4-18).

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** During the first six months of 2011, gross imports in the Day-Ahead Energy Market were 283 percent of gross imports in the Real-Time Energy Market (163 percent for the first six months of 2010). During the first six months of 2011, gross exports in the Day-Ahead Energy Market were 202 percent of gross exports in the Real-Time Energy Market (163 percent for the first six months of 2010). During the first six months of 2011, net interchange was 10,915 GWh in the Day-Ahead Energy Market and -2,949 GWh in the Real-Time Energy Market (-5,490 GWh in the Day-Ahead Energy Market and -3,356 GWh in the Real-Time Energy Market for the first six months of 2010).

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, during the first six months of 2011, there were net exports at eleven of PJM's 21 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 75 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 17 percent and PJM/Neptune (NEPT) with 15 percent of the net export volume. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 44 percent of the total net PJM exports in the Real-Time Energy Market. Nine PJM interfaces had net imports, with two importing interfaces accounting for 79 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 61 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 six months of 2011, there were net exports at nine of PJM's 21 interfaces. The top three net exporting interfaces accounted for 72 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 26 percent, PJM/FirstEnergy Corp. (FE) with 25 percent and PJM/NEPT with 21 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND). Combined, these interfaces made up 18 percent of the total net PJM exports in the Day-Ahead Energy Market. Eleven PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 83 percent of the total net imports: PJM/OVEC with 36 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 29 percent and PJM/Michigan Electric Coordinated System (MECS) with 18 percent.[4]

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent Transmission System Operator, Inc. (MISO) Interface Prices.** During the first six 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 six months of 2011, the PJM average hourly

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)).

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

Locational Marginal Price (LMP) at the PJM/MISO border was $34.28 while the MISO LMP at the border was $35.78, a difference of $1.50. While the average hourly LMP difference at the PJM/MISO border was only $1.50, the average of the absolute values of the hourly differences was $12.33. The average hourly flow during the first six months of 2011 was -1,852 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 41 percent of hours during the first six months of 2011. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $16.88. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $9.18. During the first six 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 $16.47. 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 $22.78. 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 $23.52. 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 $8.39.

- **PJM and New York ISO Interface Prices.** During the first six 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 six 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 six months of 2011, the PJM average hourly LMP at the PJM/NYISO border was $45.99 while the NYISO LMP at the border was $44.54, a difference of $1.45. While the average hourly LMP difference at the PJM/NYISO border was only $1.45, the average of the absolute value of the hourly difference was $15.40. The average hourly flow during the first six months of 2011 was -552 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 six months of 2011. During the first six months of 2011, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $13.78. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $17.09. During the first six 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 $12.21. 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 $28.07. 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 $33.29. 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 $14.03.

- **Neptune Underwater Transmission Line to Long Island, New York.** The Neptune line is a 65-mile direct current (DC) merchant 230 kV transmission line from PJM (Sayreville, New Jersey), to NYISO (Nassau County on Long Island) with a capacity of 660 MW. 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 six 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 six months of 2011, the PJM average hourly LMP at the Neptune Interface was $51.67 while the NYISO LMP at the Neptune Bus was $56.58, a difference of $4.91. While the average hourly LMP difference at the PJM/Neptune border was only $4.91, the average of the absolute value of the hourly difference was $21.37. The average hourly flow during the first six months of 2011 was -472 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 six months of 2011. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average pirce difference was $20.75. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $21.39.

- **Linden Variable Frequency Transformer (VFT) Facility.** The Linden VFT facility is a merchant transmission connection, with a capacity of 300 MW, providing a direct connection from PJM to NYISO. A variable frequency transformer allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle regulating transformer.[5] The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line. 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.[6] On June 1, 2011, the Tariff revision became effective, allowing for the bidirectional flow across the Linden VFT facility. During the first six 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 six months of 2011, the PJM average hourly LMP at the Linden Interface was $50.99 while the NYISO LMP at the Linden Bus was $53.05, a difference of $2.06. While the average hourly LMP difference at the PJM/Linden border was $2.06, the average of the absolute value of the hourly difference was $19.00. The average hourly flow during the first six months of 2011 was -164 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 61 percent of the hours during the first six months of 2011. Following June 1, 2011, when bidirectional flows were permitted across the Linden VFT Facility, a total of 100 hours, out of the 720 hours in June, were imports into PJM. Of those 100 hours, 66 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 (66 hours), the average price difference was $43.85. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when power flows were from NYISO to PJM (34 hours), the average price difference was $14.56.

- **Hudson DC Line.** The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line between Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey and Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City with a capacity of 673 MW. The connection will be a submarine AC cable system to interconnect to ConEd. While the Hudson DC line is a bidirectional line, the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights); therefore, power flows will only be from PJM to New York. The current in-service date for this line is January 31, 2012.

5 A phase angle regulating transformer (PAR) allows dispatchers to change the flow of MW over a transmission line by changing the impedance of the transmission facility.
6 See Docket No. ER11-3250-000 (March 31, 2011).

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[7] 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 six 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 six 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. On June 16th, 2011, FERC issued an Order Approving Contested Settlement.[8] This Order approved the settlement submitted by PJM and MISO regarding all issues identified in the complaint proceedings. As part of the Order, FERC also accepted all proposed JOA revisions, subject to PJM submitting a compliance filing, within 15 business days of the Order. On July 1, 2011, PJM and MISO jointly submitted the revisions to the JOA.[9]

7 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) (Accessed August 3, 2011) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (2,285 KB).
8 See 135 FERC ¶ 61,243 (2011).
9 See Docket No. ER11-3979-000 (July 1, 2011).

- **PJM, MISO and TVA Joint Reliability Coordination Agreement.**[10] 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 six months of 2011.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[11] 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 six 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.**[12] 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 six months of 2011, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[13] 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.

10 See "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed August 3, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

11 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) (Accessed August 3, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (642 KB).

12 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed August 3, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

13 See 111 FERC ¶ 61,228 (2005).

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 six months of 2011, net scheduled interchange was -1,623 GWh and net actual interchange was -1,876 GWh for a difference of 253 GWh or 15.6 percent (7.7 percent during the first six months of 2010 and 5.2 percent for the calendar year 2010).

  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.

  - **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 (-8,558 GWh during the first six 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 (2,284 GWh during the first six 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 six 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 497 GWh and the actual flow was 2,781 GWh, a difference of 2,284 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 11 GWh and the actual flow was 4,367 GWh, a difference of 4,356 GWh.

- **PJM Transmission Loading Relief Procedures (TLRs).** During the first six months of 2011, PJM issued 40 TLRs of level 3a or higher. Of the 40 TLRs issued, 21 events were TLR level 3a, and the remaining 19 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 40 TLRs during the first six months of 2011, compared to 58 during the first six 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.[14] 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 of submitting noneconomic transactions to benefit from loss surplus allocations.

- **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 (See Figure 4-18). 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 to obtain a portion of the loss surplus.

  As part of the September 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" 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 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 1,634 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

14 See 131 FERC ¶ 61,024 (2010) (order denying rehearing and accepting compliance filing); 126 FERC ¶ 61,164 (2009) (Order on request for clarification).

marginal loss surplus allocation methodology changes (September 17, 2010, through June 30, 2011). (See Figure 4-18.)

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 six months of 2011 were $10,790, compared to $1.2 million for the first six 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.[15] These modifications are currently being evaluated by PJM to develop an implementation plan.

- **Spot Import.** In 2009, PJM and the MMU 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 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.

- **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

15 See "Meeting Minutes" Minutes from PJM's MIC meeting (May 16, 2011) (Accessed on August 3, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> 121 KB).

transaction. For example, an import dispatchable transaction would specify the minimum price the market participant wishes to receive when selling into the PJM market. If the interface pricing point for the transaction is expected to be greater than the price specified by the market participant, the transaction would be loaded for the next hour. For an export dispatchable transaction, the market participant specifies the maximum price they are willing to buy from at the interface pricing point. Once the transaction is submitted and the NERC Tag is implemented, PJM should curtail the tag to 0 MW pending the real-time economic evaluation during the operating day for which the transaction is submitted. PJM dispatchers evaluate dispatchable transactions 30 minutes prior to the hour. If they believe the LMP at the interface pricing point will be economic they will load the transaction for the next hour. Once loaded, the transaction will flow for the entire hour. Dispatchable transactions receive the hourly integrated pricing point LMP for the hours when energy flows. For import transactions, if the hourly integrated import pricing point LMP is less than the price specified, the market participant is made whole through balancing operating reserve credits. Exporting dispatchable transactions are not made whole, as Schedule 6 of the PJM Open Access Transmission Tariff does not include export transactions in the calculation for balancing operating reserve credits.

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 six 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 six 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.[16] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011.

Conclusion

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

On June 1, 2011, at 0100, American Transmission System, Inc. 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 six months of 2011, including evolving transaction patterns, economics and issues. During the first six 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. A large share of both import and export activity occurred at a small number of interfaces. Four interfaces accounted for 75 percent of the total real-time net exports and two interfaces accounted for 79 percent of the real-time net import volume. Three interfaces accounted for 72 percent of the total day-ahead net exports and three interfaces accounted for 83 percent of the day-ahead net import volume.

During the first six 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,

16 See "Meeting Minutes" Minutes from PJM's MIC meeting (July 13, 2011) (Accessed on August 3, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx> 121 KB).

59 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 June 2011 (See 2010 SOM, Figure 4-1)

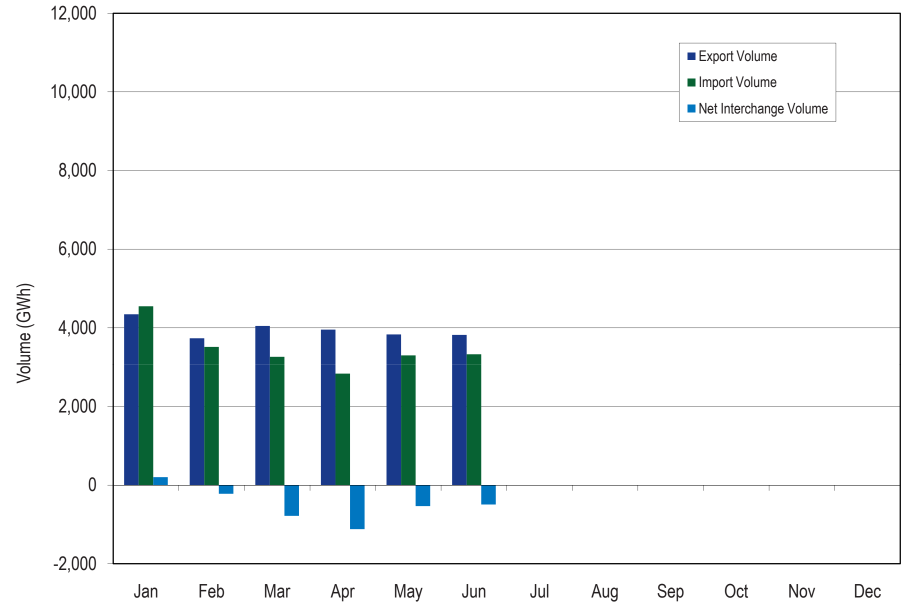


Figure 4-2 PJM day-ahead scheduled imports and exports: January through June 2011 (See 2010 SOM, Figure 4-2)

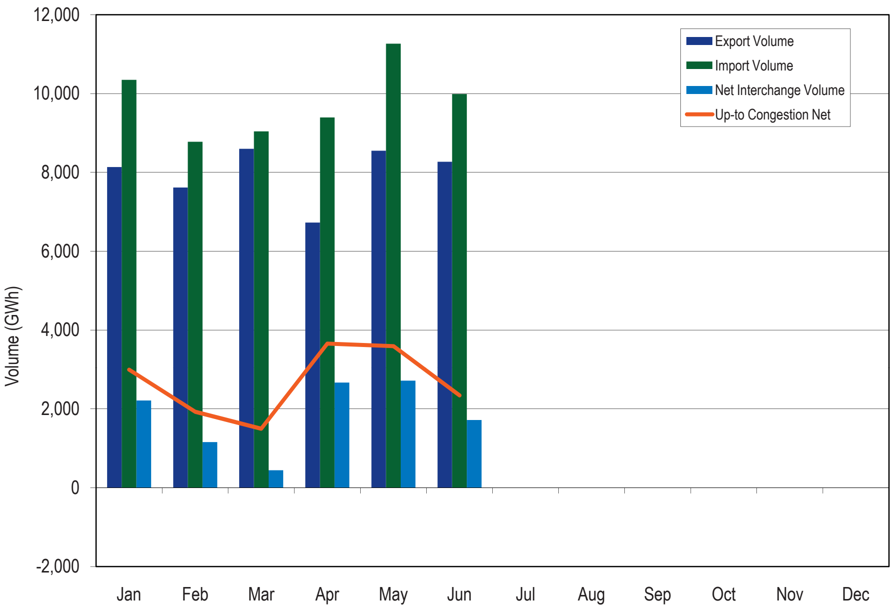


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through June 2011 (See 2010 SOM, Figure 4-3)

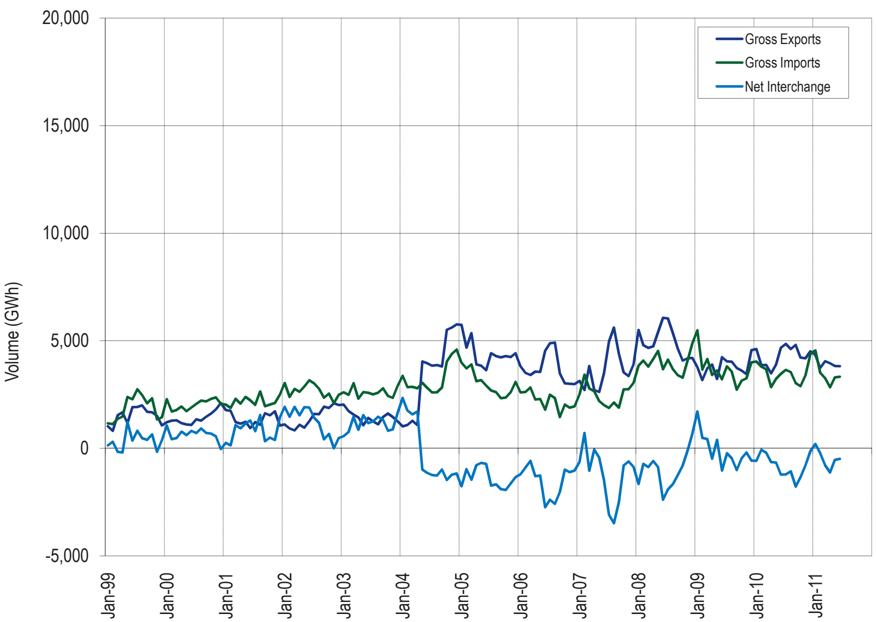
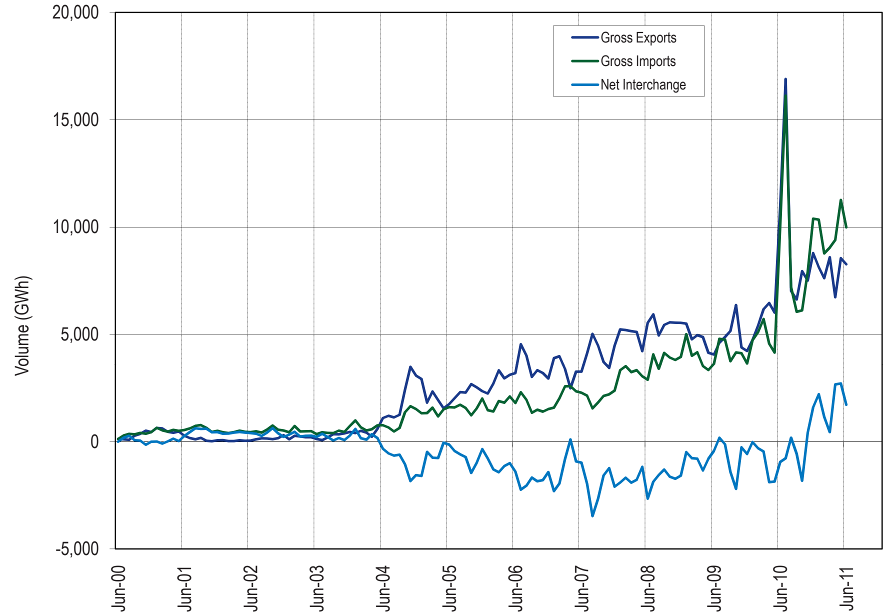


Figure 4-4 PJM scheduled import and export transaction volume history: June 2000 through June 2011 (New Figure)



Interface Imports and Exports

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	(162.6)	(76.3)	(85.5)	(48.3)	(77.6)	(59.1)	(509.4)
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	2.4
DUK	(25.6)	218.7	(17.1)	12.7	34.7	(36.8)	186.6
EKPC	(61.4)	(10.1)	5.6	135.0	41.4	106.4	216.9
LGEE	392.9	385.9	314.6	200.0	241.7	321.8	1,856.9
MEC	(426.0)	(403.3)	(462.2)	(463.2)	(478.5)	(456.3)	(2,689.5)
MISO	(77.3)	(389.0)	(744.4)	(1,131.2)	(495.8)	(675.9)	(3,513.6)
ALTE	(116.1)	(128.3)	(76.0)	(4.5)	(7.6)	(105.7)	(438.2)
ALTW	(30.9)	(14.5)	(28.6)	(49.9)	(68.8)	(83.2)	(275.9)
AMIL	(2.9)	45.5	14.3	8.6	37.9	(17.6)	85.8
CIN	(85.5)	(314.7)	(454.6)	(713.9)	(242.7)	(423.9)	(2,235.3)
CWLP	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	(554.1)
IPL	21.8	3.5	8.8	(3.3)	11.0	(12.8)	29.0
MECS	193.0	190.8	112.6	33.2	160.1	128.9	818.6
NIPS	(114.3)	(51.0)	(69.7)	(72.6)	(53.7)	(71.9)	(433.2)
WEC	(92.3)	(76.4)	(92.1)	(78.6)	(81.0)	(89.9)	(510.3)
NYISO	(1,361.0)	(1,279.3)	(1,032.0)	(864.2)	(731.7)	(673.6)	(5,941.8)
LIND	(159.1)	(148.1)	(117.7)	(131.7)	(93.0)	(80.4)	(730.0)
NEPT	(412.9)	(378.8)	(383.7)	(290.8)	(387.5)	(241.0)	(2,094.7)
NYIS	(789.0)	(752.4)	(530.6)	(441.7)	(251.2)	(352.2)	(3,117.1)
OVEC	1,242.2	1,110.7	1,065.8	1,019.0	1,030.7	1,014.6	6,483.0
TVA	681.6	222.8	170.3	19.9	(98.5)	(36.7)	959.4
Total	202.8	(219.9)	(784.9)	(1,120.3)	(533.6)	(493.2)	(2,949.1)

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	6.4	7.4	4.6	6.6	23.4	67.7	116.1
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	2.4
DUK	271.7	309.8	186.2	208.2	197.7	184.4	1,358.0
EKPC	31.7	46.5	41.0	143.3	85.5	112.3	460.3
LGEE	393.0	386.3	324.1	233.6	250.3	334.6	1,921.9
MEC	53.2	30.8	19.1	0.0	0.0	0.0	103.1
MISO	1,141.5	833.9	736.6	409.5	718.2	542.8	4,382.5
ALTE	0.0	0.0	0.0	0.0	0.0	0.2	0.2
ALTW	0.0	0.0	0.0	0.0	0.0	0.9	0.9
AMIL	23.9	68.0	42.2	26.0	55.4	37.8	253.3
CIN	400.0	270.3	315.2	180.8	348.0	260.0	1,774.3
CWLP	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	906.6
IPL	25.4	4.8	15.3	5.6	19.3	66.9	137.3
MECS	250.9	270.3	241.4	141.4	224.3	176.7	1,305.0
NIPS	0.0	0.0	0.2	0.2	0.0	0.0	0.4
WEC	4.5	0.0	0.0	0.0	0.0	0.0	4.5
NYISO	681.0	534.7	646.6	686.3	911.4	976.1	4,436.1
LIND	0.0	0.0	0.0	0.0	0.1	14.5	14.6
NEPT	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	4,421.5
OVEC	1,242.2	1,110.7	1,091.3	1,019.0	1,030.7	1,014.6	6,508.5
TVA	725.7	255.5	212.0	128.8	79.7	92.0	1,493.7
Total	4,546.4	3,515.6	3,261.5	2,835.3	3,296.9	3,326.9	20,782.6

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	169.0	83.7	90.1	54.9	101.0	126.8	625.5
CPLW	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	1,171.4
EKPC	93.1	56.6	35.4	8.3	44.1	5.9	243.4
LGEE	0.1	0.4	9.5	33.6	8.6	12.8	65.0
MEC	479.2	434.1	481.3	463.2	478.5	456.3	2,792.6
MISO	1,218.8	1,222.9	1,481.0	1,540.7	1,214.0	1,218.7	7,896.1
ALTE	116.1	128.3	76.0	4.5	7.6	105.9	438.4
ALTW	30.9	14.5	28.6	49.9	68.8	84.1	276.8
AMIL	26.8	22.5	27.9	17.4	17.5	55.4	167.5
CIN	485.5	585.0	769.8	894.7	590.7	683.9	4,009.6
CWLP	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	1,460.7
IPL	3.6	1.3	6.5	8.9	8.3	79.7	108.3
MECS	57.9	79.5	128.8	108.2	64.2	47.8	486.4
NIPS	114.3	51.0	69.9	72.8	53.7	71.9	433.6
WEC	96.8	76.4	92.1	78.6	81.0	89.9	514.8
NYISO	2,042.0	1,814.0	1,678.6	1,550.5	1,643.1	1,649.7	10,377.9
LIND	159.1	148.1	117.7	131.7	93.1	94.9	744.6
NEPT	412.9	378.8	383.7	290.8	387.5	241.0	2,094.7
NYIS	1,470.0	1,287.1	1,177.2	1,128.0	1,162.5	1,313.8	7,538.6
OVEC	0.0	0.0	25.5	0.0	0.0	0.0	25.5
TVA	44.1	32.7	41.7	108.9	178.2	128.7	534.3
Total	4,343.6	3,735.5	4,046.4	3,955.6	3,830.5	3,820.1	23,731.7

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	(11.3)	89.8	126.7	234.5	159.9	(83.0)	516.6
CPLW	17.1	6.4	1.9	11.0	6.0	15.4	57.8
DUK	91.7	115.8	41.0	789.1	234.0	(240.7)	1,030.9
EKPC	(27.5)	(18.4)	27.8	6.8	(5.3)	0.9	(15.7)
LGEE	19.0	1.8	2.0	16.6	35.6	1.8	76.8
MEC	(458.7)	(421.4)	(463.2)	(455.2)	(472.2)	(437.3)	(2,708.0)
MISO	2,144.3	904.6	(182.2)	697.2	452.4	1,481.0	5,497.3
ALTE	1,996.5	908.2	99.1	833.9	1,037.3	1,333.0	6,208.0
ALTW	164.8	(49.7)	(48.1)	(40.1)	(7.3)	139.3	158.9
AMIL	34.6	70.2	67.5	31.0	33.6	(4.6)	232.3
CIN	(125.8)	(90.5)	(175.1)	(94.3)	(18.1)	(131.4)	(635.2)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	(189.4)	(339.7)	(317.2)	(479.3)	(1,299.6)	(1.5)	(2,626.7)
IPL	(175.6)	(162.6)	(163.9)	(75.1)	(123.5)	(97.9)	(798.6)
MECS	742.4	580.2	567.2	591.2	992.5	336.2	3,809.7
NIPS	(280.6)	(111.0)	(130.3)	(65.9)	(108.8)	(90.8)	(787.4)
WEC	(22.6)	99.5	(81.4)	(4.2)	(53.7)	(1.3)	(63.7)
NYISO	(892.0)	(681.9)	(496.7)	(220.9)	611.3	(242.7)	(1,922.9)
LIND	(105.0)	(104.7)	(77.9)	(110.8)	(75.0)	(171.2)	(644.6)
NEPT	(427.9)	(379.7)	(385.0)	(298.1)	(405.2)	(250.0)	(2,145.9)
NYIS	(359.1)	(197.5)	(33.8)	188.0	1,091.5	178.5	867.6
OVEC	1,046.0	1,051.1	1,279.5	1,502.7	1,636.3	1,167.6	7,683.2
TVA	282.8	111.2	106.7	85.9	56.5	55.6	698.7
Total	2,211.4	1,159.0	443.5	2,667.7	2,714.5	1,718.6	10,914.7

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	137.6	146.3	197.4	305.0	242.6	29.5	1,058.4
CPLW	19.5	6.5	8.1	13.9	24.6	27.2	99.8
DUK	150.8	155.5	88.5	935.0	269.0	50.9	1,649.7
EKPC	5.4	0.0	28.3	6.8	6.3	2.8	49.6
LGEE	21.6	2.1	13.5	17.1	40.8	41.6	136.7
MEC	21.7	19.8	20.1	8.2	15.9	67.5	153.2
MISO	7,393.7	5,782.6	5,316.8	4,391.0	5,686.9	5,791.8	34,362.8
ALTE	4,872.3	3,576.6	3,109.0	2,156.0	2,959.3	3,808.9	20,482.1
ALTW	375.6	52.1	29.0	19.3	74.1	284.8	834.9
AMIL	44.8	71.1	70.7	34.2	35.8	45.2	301.8
CIN	266.2	440.5	360.6	511.2	263.4	728.0	2,569.9
CWLP	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	586.7
IPL	17.0	2.9	0.0	6.5	2.8	1.7	30.9
MECS	1,409.4	1,207.9	1,438.1	1,402.0	2,167.9	772.1	8,397.4
NIPS	32.0	48.2	27.0	33.9	11.6	29.2	181.9
WEC	143.7	242.8	141.4	172.4	155.0	121.9	977.2
NYISO	910.1	988.6	1,149.1	1,399.2	2,467.1	1,560.2	8,474.3
LIND	0.0	0.0	0.0	0.0	0.0	8.7	8.7
NEPT	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	8,465.6
OVEC	1,272.8	1,355.2	1,898.8	1,976.7	2,223.0	1,886.6	10,613.1
TVA	412.1	318.7	318.9	341.8	286.8	529.3	2,207.6
Total	10,345.3	8,775.3	9,039.5	9,394.7	11,263.0	9,987.4	58,805.2

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

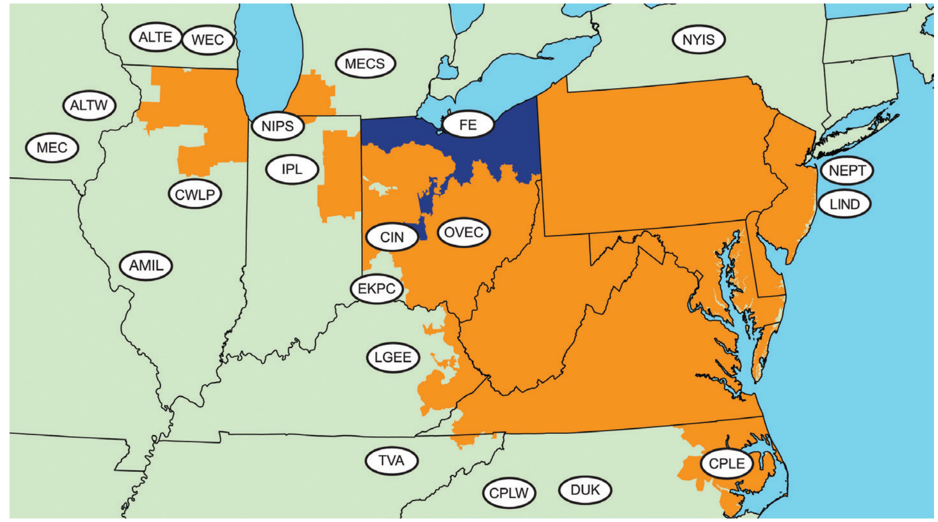
	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	148.9	56.5	70.7	70.5	82.7	112.5	541.8
CPLW	2.4	0.1	6.2	2.9	18.6	11.8	42.0
DUK	59.1	39.7	47.5	145.9	35.0	291.6	618.8
EKPC	32.9	18.4	0.5	0.0	11.6	1.9	65.3
LGEE	2.6	0.3	11.5	0.5	5.2	39.8	59.9
MEC	480.4	441.2	483.3	463.4	488.1	504.8	2,861.2
MISO	5,249.4	4,878.0	5,499.0	3,693.8	5,234.5	4,310.8	28,865.5
ALTE	2,875.8	2,668.4	3,009.9	1,322.1	1,922.0	2,475.9	14,274.1
ALTW	210.8	101.8	77.1	59.4	81.4	145.5	676.0
AMIL	10.2	0.9	3.2	3.2	2.2	49.8	69.5
CIN	392.0	531.0	535.7	605.5	281.5	859.4	3,205.1
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	422.1	480.2	458.2	534.8	1,316.6	1.5	3,213.4
IPL	192.6	165.5	163.9	81.6	126.3	99.6	829.5
MECS	667.0	627.7	870.9	810.8	1,175.4	435.9	4,587.7
NIPS	312.6	159.2	157.3	99.8	120.4	120.0	969.3
WEC	166.3	143.3	222.8	176.6	208.7	123.2	1,040.9
NYISO	1,802.1	1,670.5	1,645.8	1,620.1	1,855.8	1,802.9	10,397.2
LIND	105.0	104.7	77.9	110.8	75.0	179.9	653.3
NEPT	427.9	379.7	385.0	298.1	405.2	250.0	2,145.9
NYIS	1,269.2	1,186.1	1,182.9	1,211.2	1,375.6	1,373.0	7,598.0
OVEC	226.8	304.1	619.3	474.0	586.7	719.0	2,929.9
TVA	129.3	207.5	212.2	255.9	230.3	473.7	1,508.9
Total	8,133.9	7,616.3	8,596.0	6,727.0	8,548.5	8,268.8	47,890.5

Interface Pricing

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

	Jan	Feb	Mar	Apr	May	Jun
ALTE	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active

Figure 4-5 PJM's footprint and its external interfaces[17] (See 2010 SOM, Figure 4-4)



17 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.

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

PJM 2011 Pricing Points (January through June)						
	Jan	Feb	Mar	Apr	May	Jun
CPLEEXP	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active
MICHFE	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active

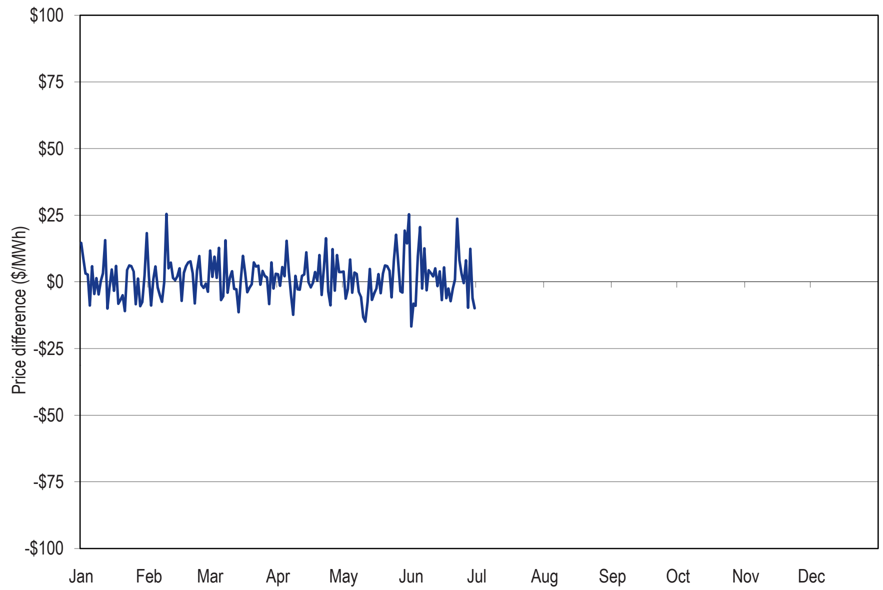
Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

PJM and MISO Interface Prices

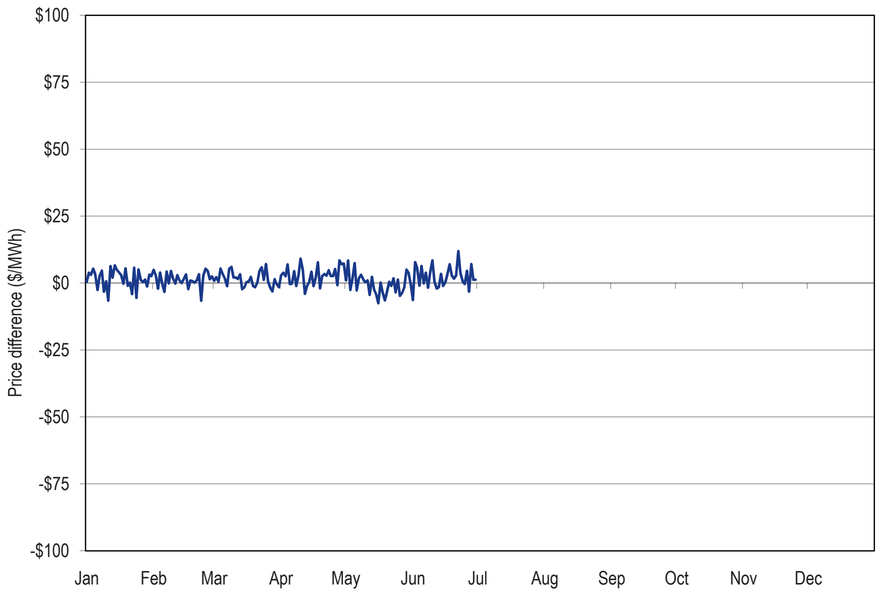
Real-Time Prices

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



Day-Ahead Prices

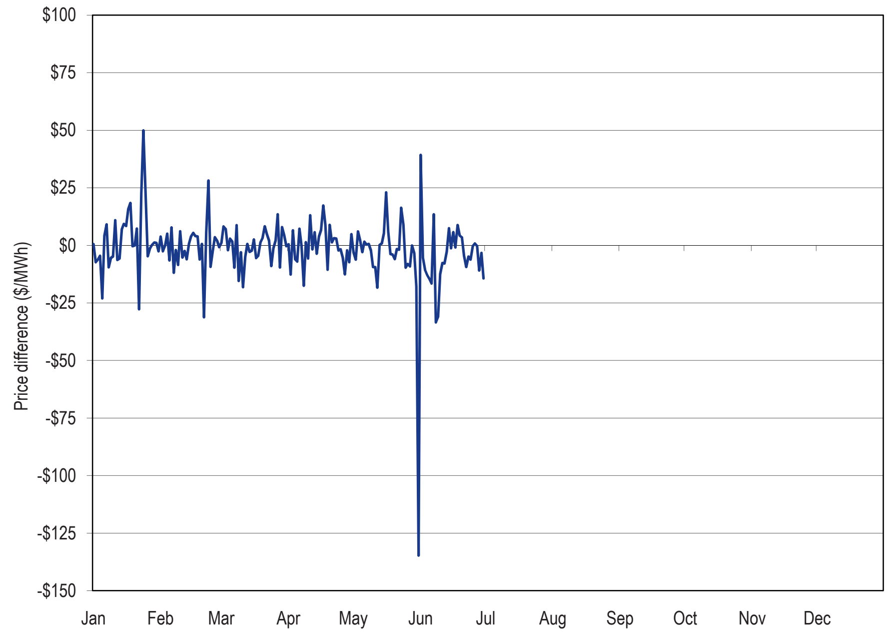
Figure 4-7 Day-ahead daily hourly average price difference (MISO interface minus PJM/MISO): January through June 2011 (See 2010 SOM, Figure 4-6)



PJM and NYISO Interface Prices

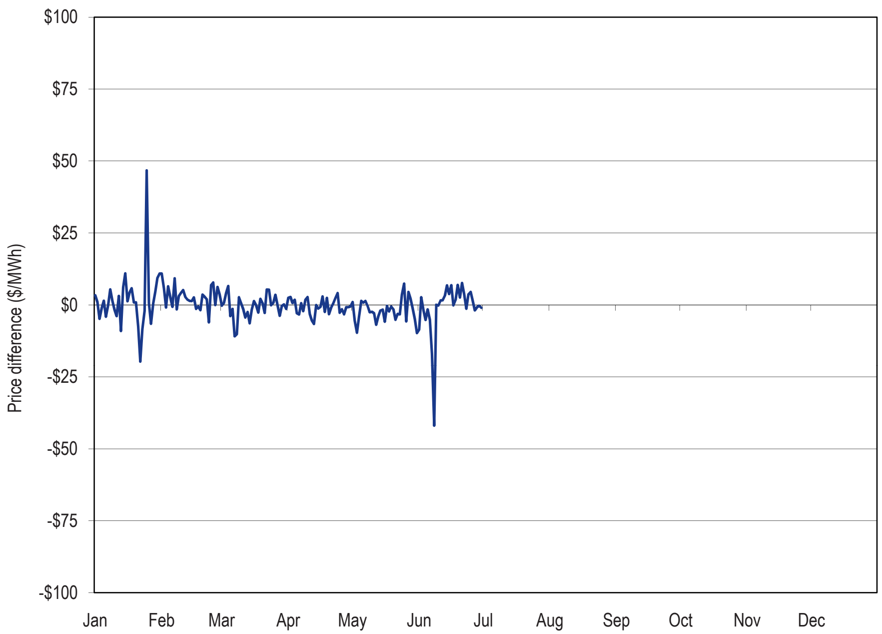
Real-Time Prices

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

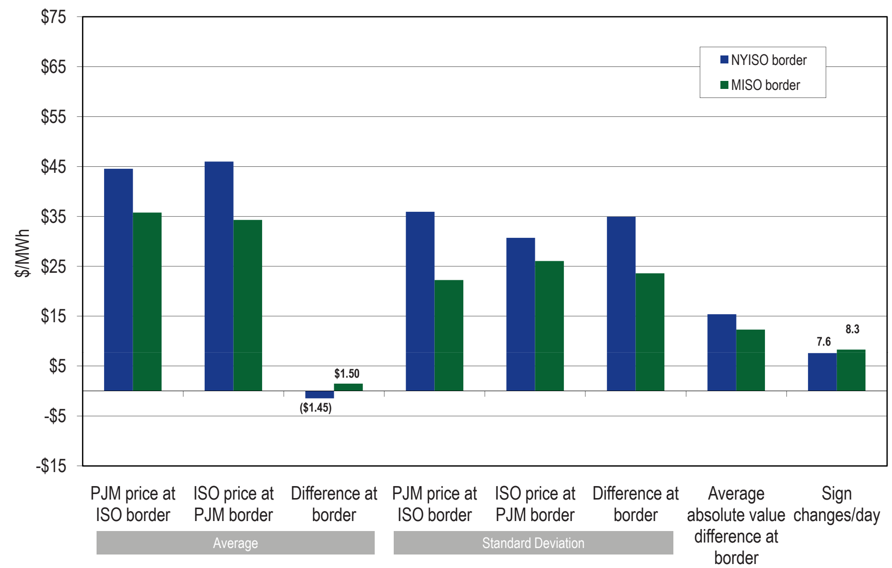
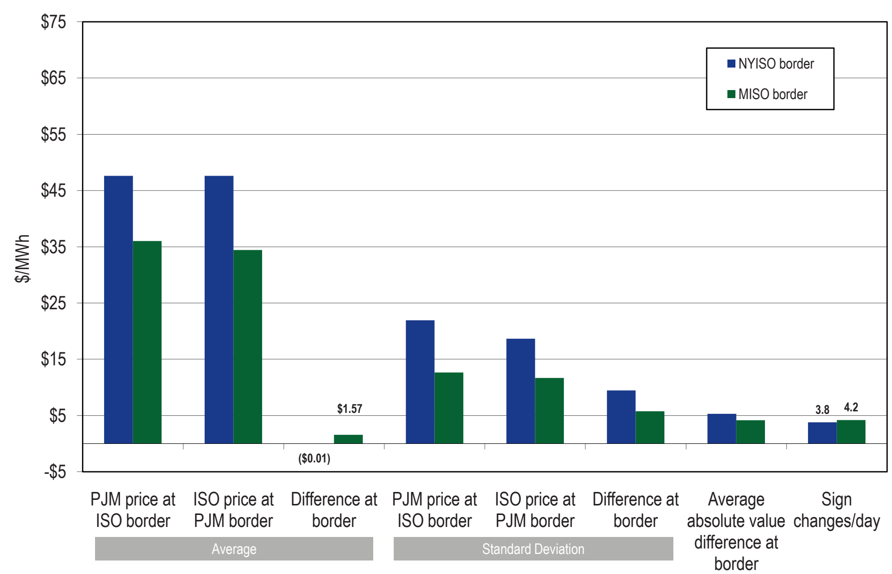
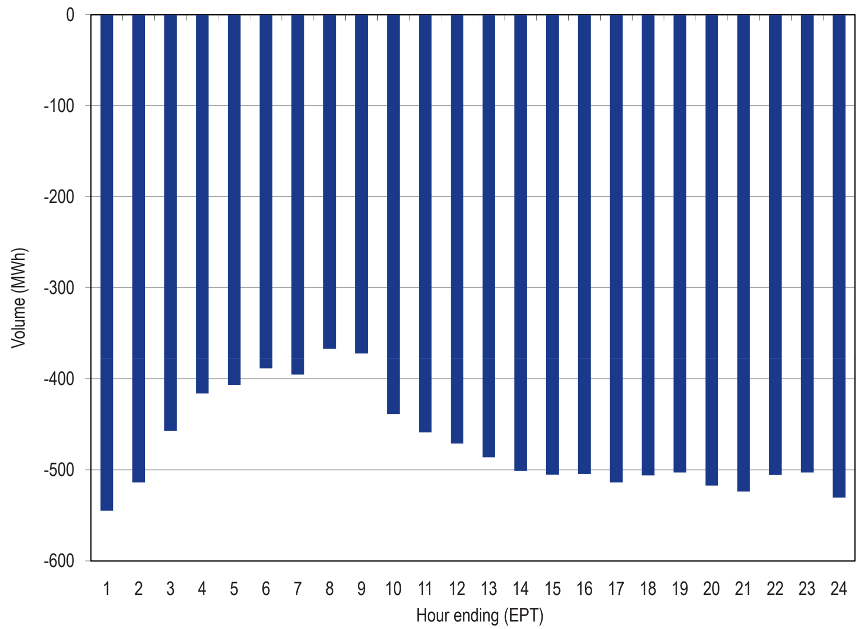


Figure 4-11 PJM, NYISO and MISO day-ahead border price averages: January through June 2011 (See 2010 SOM, Figure 4-10)



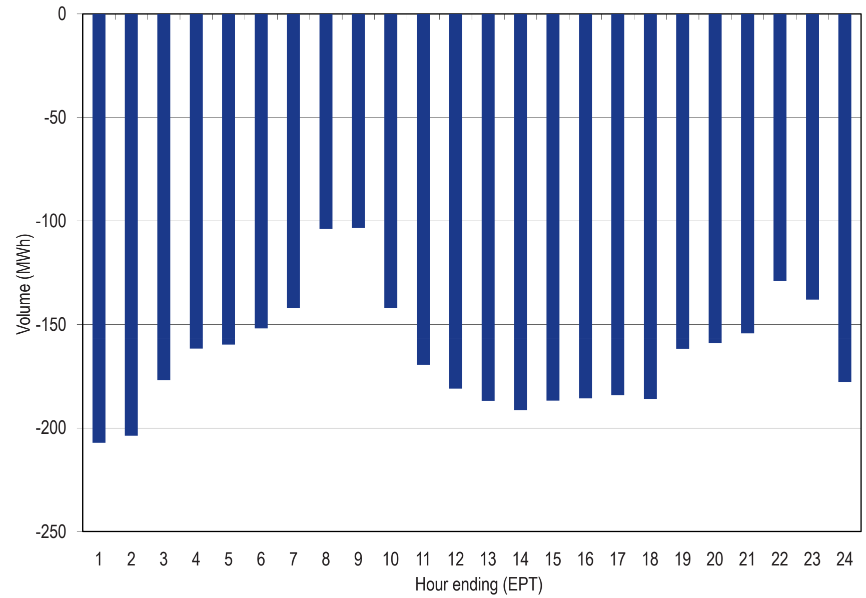
Neptune Underwater Transmission Line to Long Island, New York

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



Linden Variable Frequency Transformer (VFT) facility

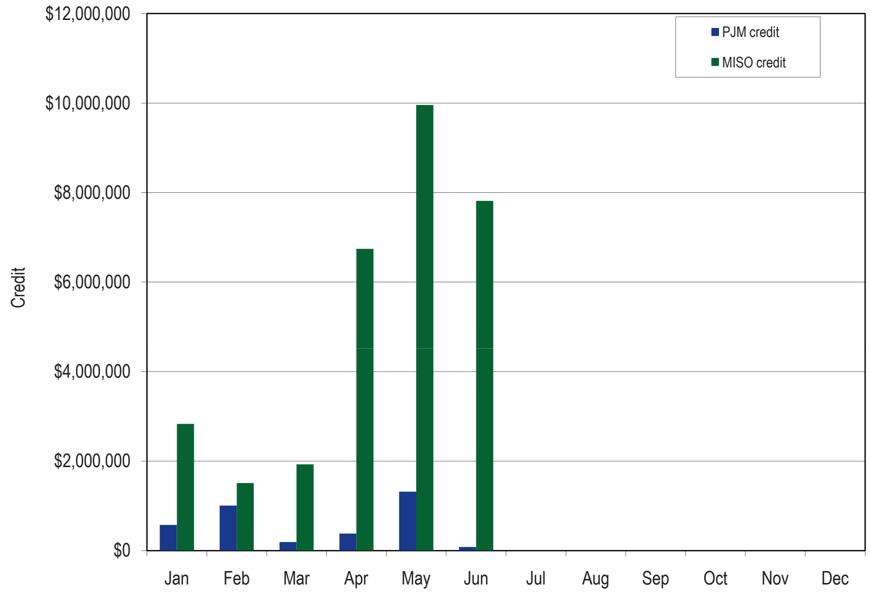
Figure 4-13 Linden hourly average flow: January through June 2011 (See 2010 SOM, Figure 4-12)



Operating Agreements with Bordering Areas

PJM and MISO Joint Operating Agreement

Figure 4-14 Credits for coordinated congestion management: January through June 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 June 2011 (See 2010 SOM, Table 4-9)

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	($1,064,896)	($59)	($1,064,955)	($10,265,822)	$0	($10,265,822)
Congestion Credit			$87,274			($10,433,963)
Adjustments			$15,121			$1,007,268
Net Charge			($1,167,351)			($839,127)

Interchange Transaction Issues

Loop Flows

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

	Actual	Net Scheduled	Difference (GWh)	Difference (Percent of Net Scheduled)
CPLE	4,367	11	4,356	39,600%
CPLW	(900)	2	(902)	(45,100%)
DUK	(1,101)	187	(1,288)	(689%)
EKPC	1,508	217	1,291	595%
LGEE	678	1,857	(1,179)	(63%)
MEC	(863)	(2,685)	1,822	(68%)
MISO	(8,042)	(2,208)	(5,834)	264%
ALTE	(2,900)	(438)	(2,462)	562%
ALTW	(1,009)	(276)	(733)	266%
AMIL	5,754	43	5,711	13,281%
CIN	333	(362)	695	(192%)
CWLP	(82)	-	(82)	0%
FE	(3,464)	(1,005)	(2,459)	245%
IPL	877	(46)	923	(2,007%)
MECS	(7,739)	819	(8,558)	(1,045%)
NIPS	(2,251)	(433)	(1,818)	420%
WEC	2,439	(510)	2,949	(578%)
NYISO	(5,160)	(5,984)	824	(14%)
LIND	(714)	(714)	-	0%
NEPT	(2,050)	(2,050)	-	0%
NYIS	(2,396)	(3,220)	824	(26%)
OVEC	4,856	6,483	(1,627)	(25%)
TVA	2,781	497	2,284	460%
Total	(1,876)	(1,623)	(253)	15.6%

Loop Flows at PJM's Southern Interfaces

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

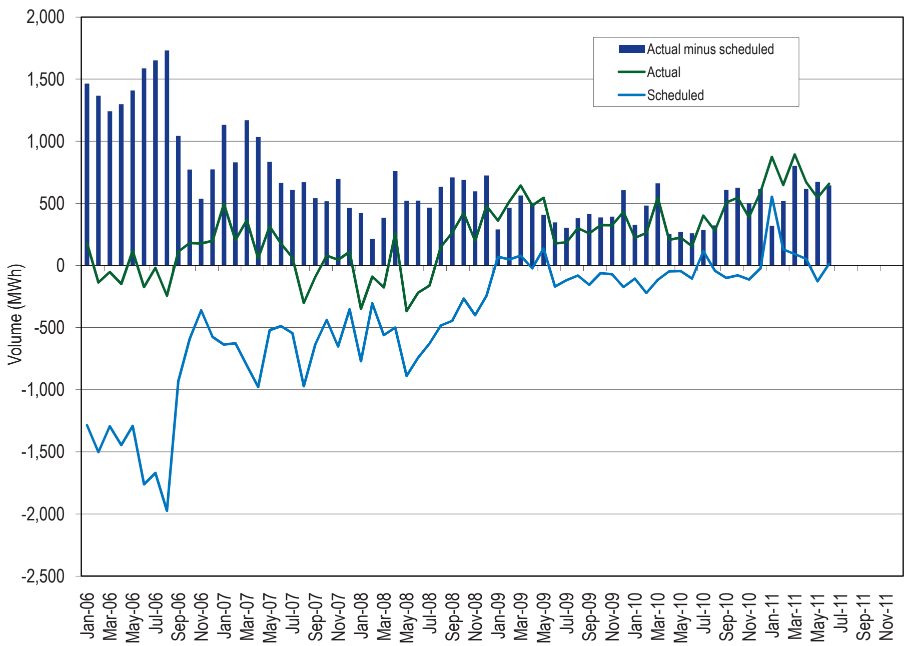
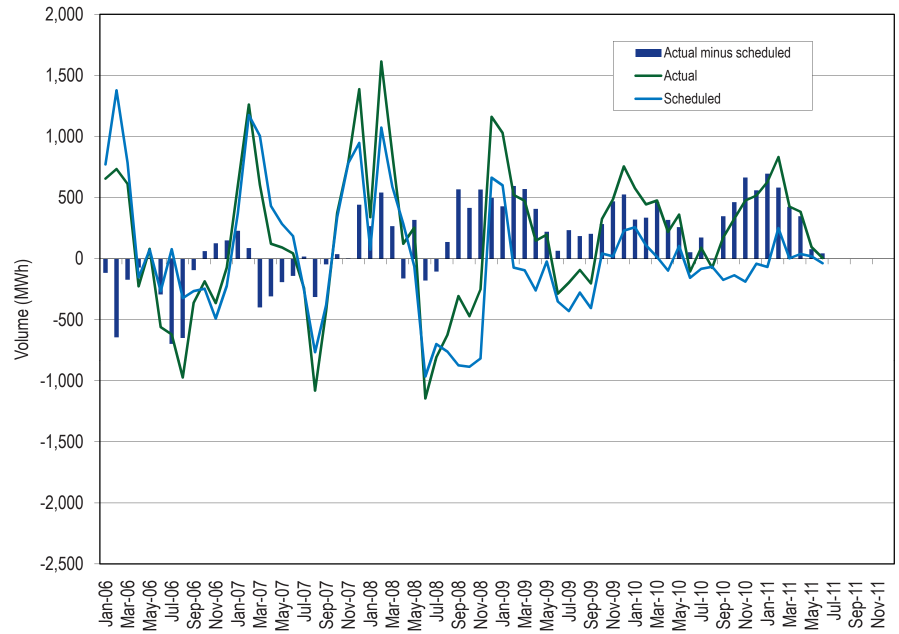


Figure 4-16 Southeast actual and scheduled flows: January 2006 through June 2011 (See 2010 SOM, Figure 4-15)



TLR's

Table 4-11 PJM and MISO TLR procedures: Calendar year 2010 and January through June 2011[18] (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

18 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 June 2011 (See 2010 SOM, Table 4-11)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2011	ICTE	14	6	103	29	25	0	177
	MISO	46	23	1	6	5	0	81
	NYIS	119	0	0	0	0	0	119
	ONT	56	0	0	0	0	0	56
	PJM	21	19	0	0	0	0	40
	SWPP	141	170	1	16	15	0	343
	TVA	43	67	3	1	14	0	128
	VACS	9	1	0	0	0	0	10
Total		449	286	108	52	59	0	954

Up-To Congestion

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

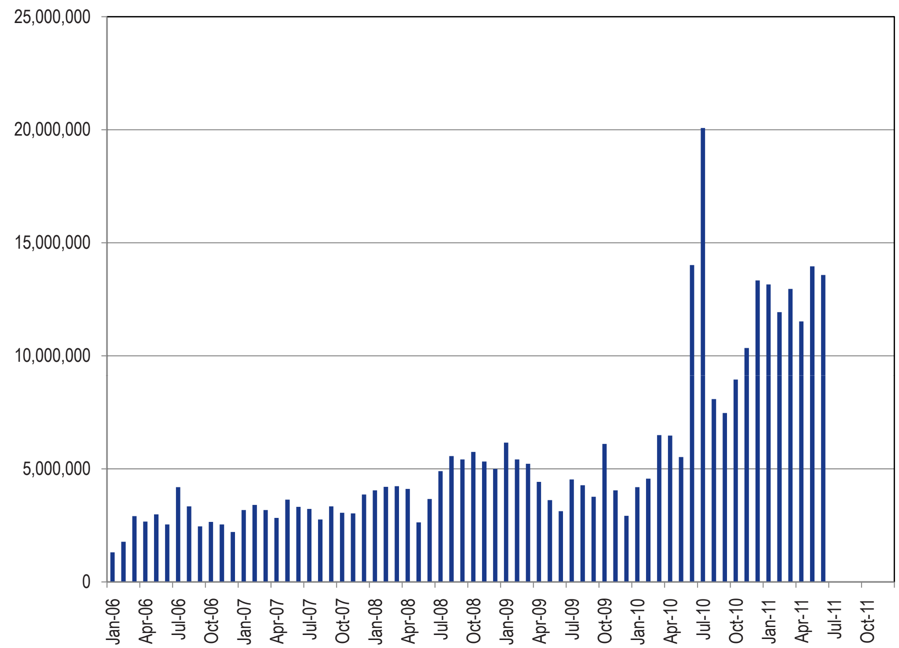


Figure 4-18 Unique up-to congestion bids with approved MWh: March 2009 through June 2011 (New Figure)

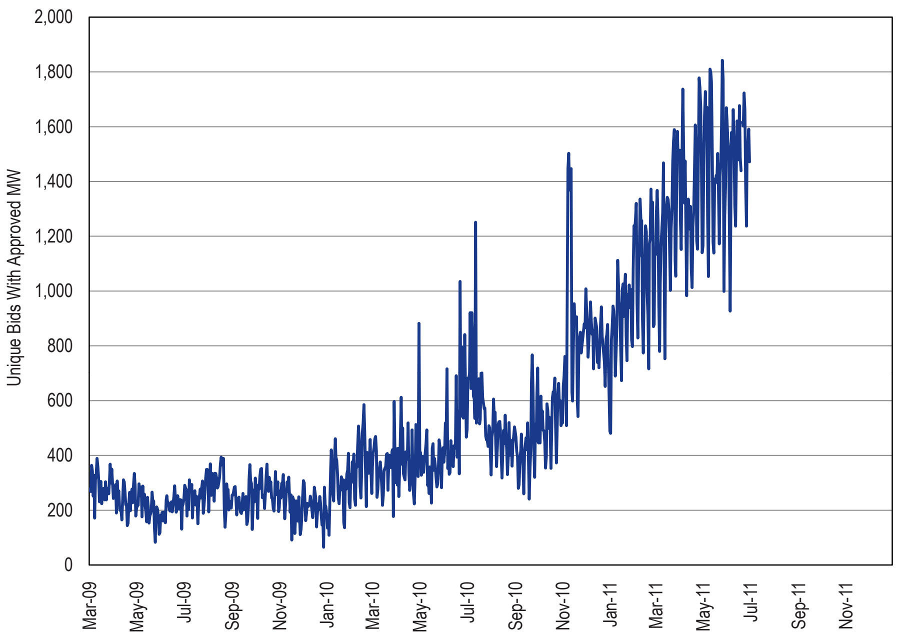


Figure 4-19 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction: January through June 2011 (See 2010 SOM, Figure 4-20)

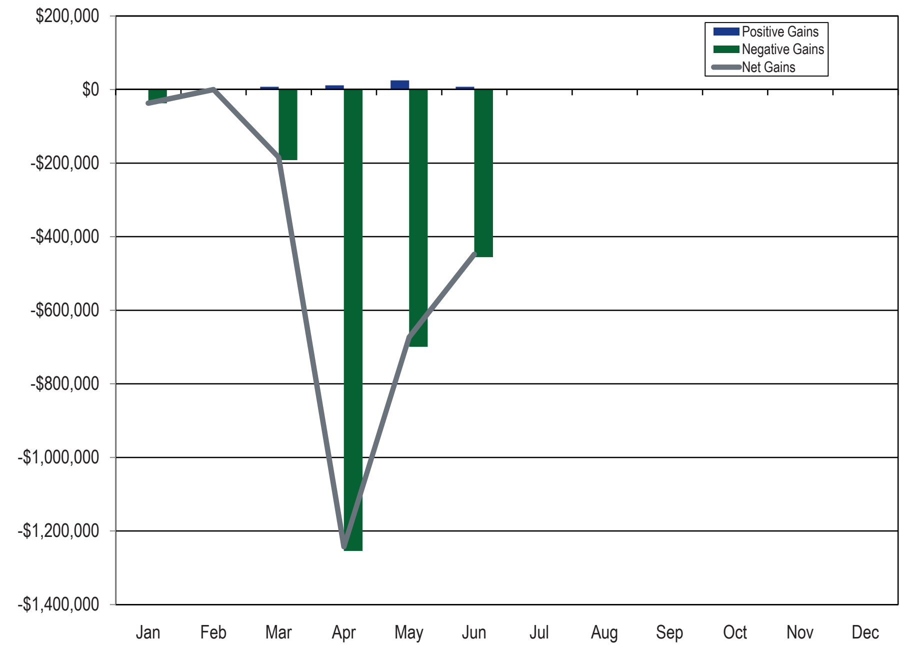
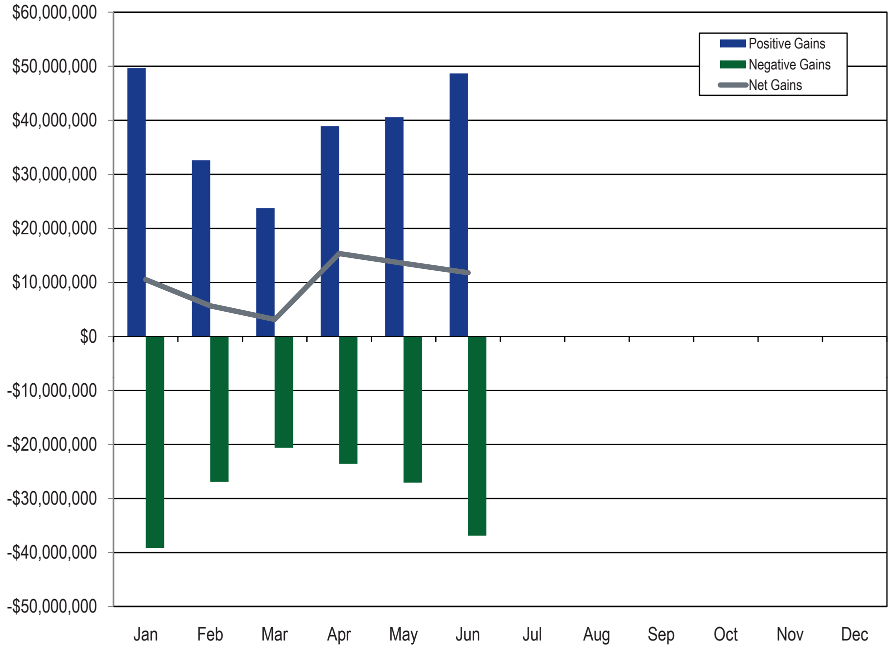


Table 4-13 Up-to congestion MW by Import, Export and Wheels: January through June 2006 through 2011 (See 2010 SOM, Table 4-12)

Jan - Jun	Import MW	Export MW	Wheeling MW	Total MW	Percent Imports	Percent Exports	Percent Wheels
2006	5,089,349	8,836,701	268,269	14,194,319	35.9%	62.3%	1.9%
2007	7,422,198	11,849,133	295,553	19,566,883	37.9%	60.6%	1.5%
2008	7,936,275	14,342,508	630,259	22,909,042	34.6%	62.6%	2.8%
2009	12,144,324	15,028,627	802,512	27,975,462	43.4%	53.7%	2.9%
2010	54,662,719	48,723,549	6,147,957	109,534,225	49.9%	44.5%	5.6%
2011	45,456,976	29,214,227	2,426,526	77,097,729	59.0%	37.9%	3.1%

Figure 4-20 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Energy Market transaction: January through June 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 June 2007 through 2011 (See 2010 SOM, Table 4-13)

Jan - Jun	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2007	$52.29	$44.67	$47.71	$46.68	$4.58	($3.04)	$5.61	($2.01)
2008	$64.90	$54.33	$58.07	$58.02	$6.83	($3.74)	$6.88	($3.69)
2009	$39.11	$34.43	$36.07	$36.07	$3.03	($1.64)	$3.03	($1.64)
2010	$43.25	$36.01	$39.03	$38.73	$4.21	($3.02)	$4.51	($2.72)
2011	$43.12	$37.75	$40.04	$40.04	$3.08	($2.29)	$3.08	($2.29)

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

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$40.87	$42.17	$40.04	$40.04	$0.83	$2.13
PEC	$41.62	$43.98	$40.04	$40.04	$1.58	$3.94
NCMPA	$41.57	$41.78	$40.04	$40.04	$1.53	$1.74

Figure 4-21 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2011 (See 2010 SOM, Figure 4-22)

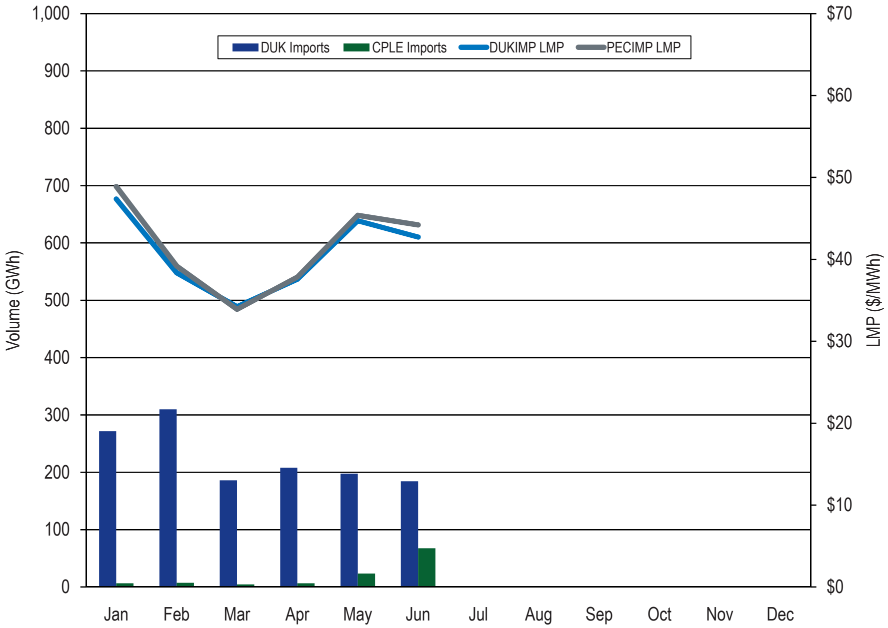


Figure 4-22 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2011 (See 2010 SOM, Figure 4-23)

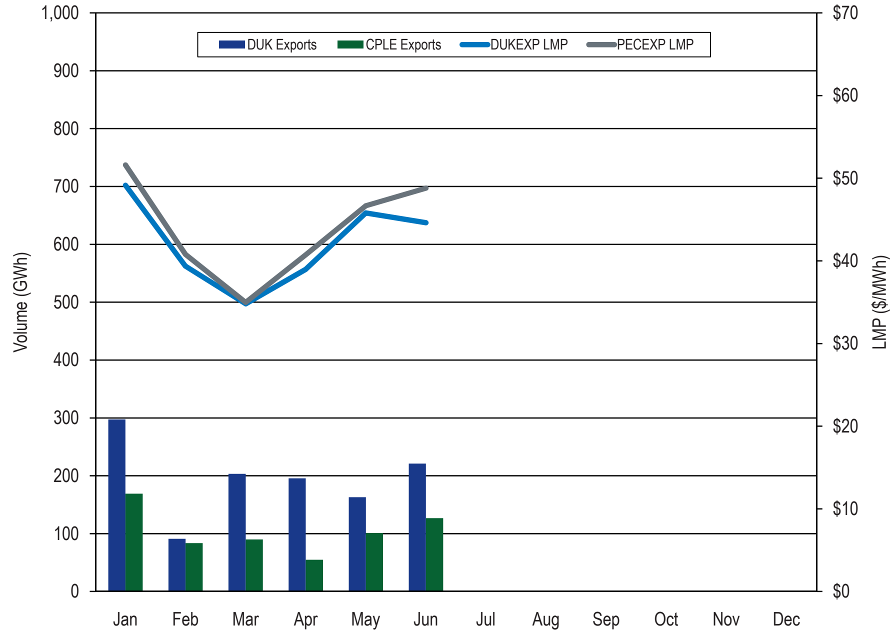


Table 4-16 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through June 2007 through 2011 (See 2010 SOM, Table 4-15)

Jan - Jun	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2007	$51.92	$44.92	$48.05	$46.66	$3.86	($3.13)	$5.25	($1.74)
2008	$66.19	$54.92	$58.97	$58.97	$7.22	($4.05)	$7.22	($4.05)
2009	$39.55	$34.49	$36.29	$36.29	$3.26	($1.80)	$3.26	($1.80)
2010	$44.78	$36.63	$39.40	$39.40	$5.38	($2.77)	$5.38	($2.77)
2011	$43.21	$38.21	$39.88	$39.88	$3.33	($1.67)	$3.33	($1.67)

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

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.16	$43.11	$39.88	$39.88	$1.27	$3.23
PEC	$41.86	$44.75	$39.88	$39.88	$1.97	$4.87
NCMPA	$41.64	$42.41	$39.88	$39.88	$1.76	$2.52

Figure 4-23 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2011 (See 2010 SOM, Figure 4-24)

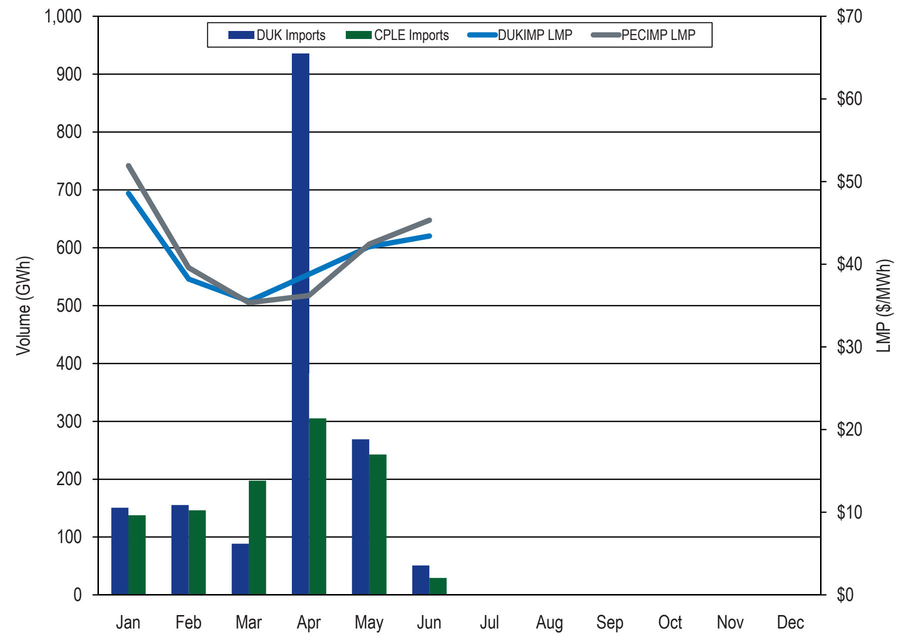
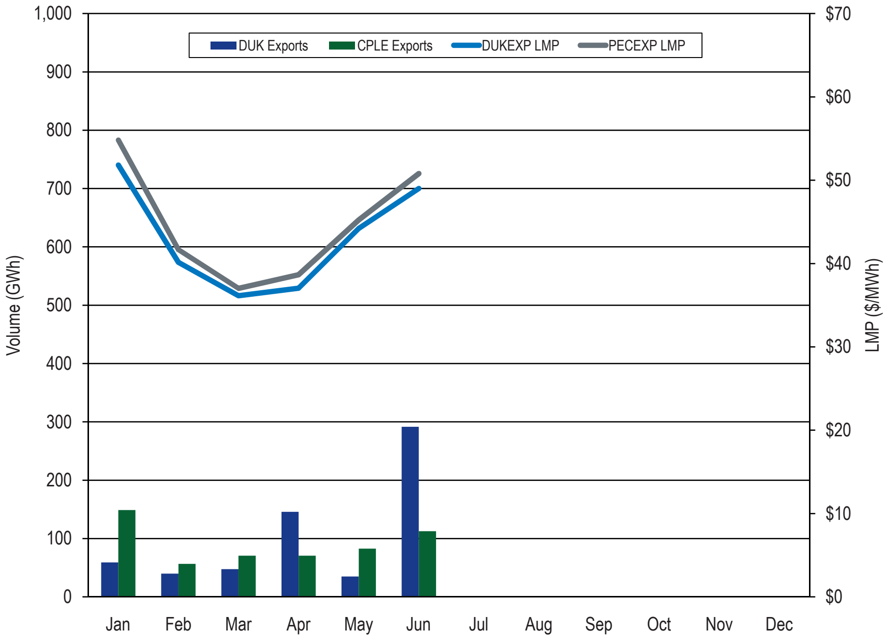
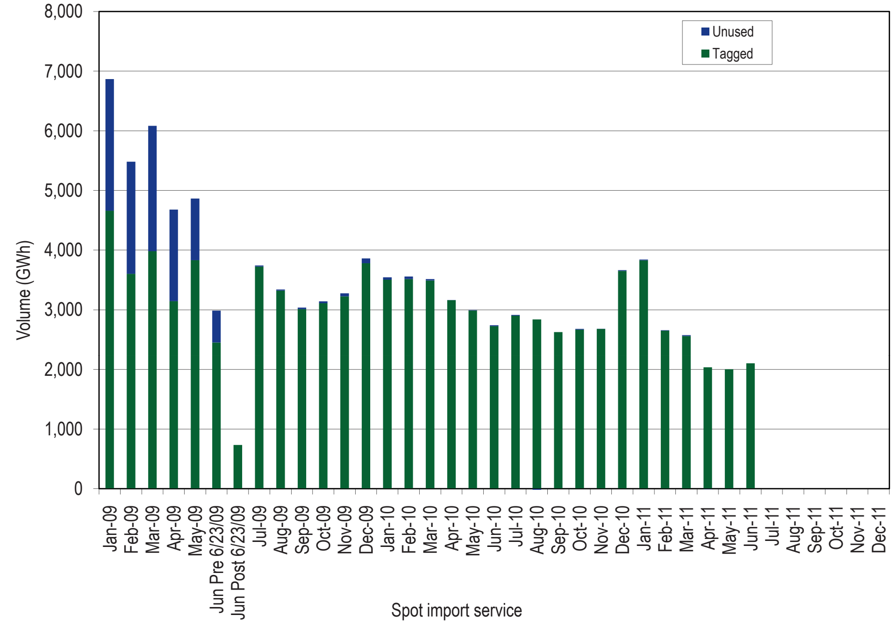


Figure 4-24 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2011 (See 2010 SOM, Figure 4-25)



Spot Import

Figure 4-25 Spot import service utilization: January 2009 through June 2011 (See 2010 SOM, Figure 4-27)



Willing to Pay Congestion and Not Willing to Pay Congestion

Table 4-18 Monthly uncollected congestion charges: Calendar year 2010 and January through June 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	
Aug	$731,539	
Sep	$119,162	
Oct	$257,448	
Nov	$30,843	
Dec	$127,176	
Total	$3,314,018	$10,790

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 six 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 and the submitted sell offer exceeded the defined offer cap.

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

- Market design was evaluated as mixed because while there are many positive features of the 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, a definition of DR which permits an inferior product to substitute for capacity and inadequate rules to address buyer side market power.

Highlights

- The 2014/2015 Base Residual Auction was run in the second quarter of 2011. The RTO annual resource clearing price in the 2014/2015 RPM Base Residual Auction was $125.99 per MW-day, an increase of $98.26 per MW-day from the 2013/2014 RPM Base Residual Auction resource clearing price.

- 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 $127.46 per MW-day in 2014.

- Average PJM equivalent demand forced outage rate (EFORd) increased from 7.8 percent in the first six months of 2010 to 7.9 percent in the first six months of 2011.

- The PJM aggregate equivalent availability factor (EAF) decreased from 84.3 percent in the first six months of 2010 to 82.2 percent in the first six months of 2011. The equivalent maintenance outage factor (EMOF) increased from 2.7 percent in the first six months of 2010 to 3.1 percent in the first six months of 2011, the equivalent planned outage factor (EPOF) increased from 8.4 percent from the first six months of 2010 to 9.7 percent in the first six months of 2011, and the equivalent forced outage factor (EFOF) increased from 4.6 percent in the first six months of 2010 to 5.0 percent in the first six months of 2011.

Recommendations

- In this 2011 *Quarterly State of the Market Report for PJM: January through June*, 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 is conducted if PJM determines that an unforced capacity resource shortage exceeds 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[3] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13, and four months, respectively, prior to the delivery year. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[4]

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

Market Structure

- **Supply.** Offered MW in the 2014/2015 RPM Base Residual Auction totaled 160,486.3 MW, a decrease of 411.8 MW from the 2013/2014 RPM Base Residual Auction.

- **Demand.** The overall RTO reliability requirement, from which the Variable Resource Requirement (VRR) curve is developed, decreased 1,665.6 MW from 149,988.7 MW to 148,323.1 MW. The decrease in the reliability requirement adjusted for FRR, due to an increase in the preliminary FRR obligation offset by the inclusion of the Duke Zone in the preliminary forecast peak load, shifted the RTO market VRR curve to the left.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2011 Quarterly State of the Market Report for PJM: January through June*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
2 See 126 FERC ¶ 61,275 (2009) at P 86.
3 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
4 See 126 FERC ¶ 61,275 (2009) at P 88.
5 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

- **Market Concentration.** For the 2014/2015 delivery year, all defined markets failed the preliminary market structure screen (PMSS).[6] As a result, all capacity market sellers owning or controlling any generation capacity resource located in the entire PJM Region shall be required to provide the information specified in Section 6.7(b) of Attachment DD of the PJM Open Access Transmission Tariff (OATT). In the 2014/2015 Base Residual Auction all participants in the RTO as well as PS North market failed the three pivotal supplier (TPS) market structure test.[7] All participants included in the incremental supply of MAAC passed the test. The incremental demand consists of the MW needed inside the LDA to relieve the constraint. Incremental demand in MAAC was 411.4 MW. The incremental supply in MAAC, considered in the application of the three pivotal supplier test, was 2,415.6 MW.[8] Offer caps were applied to all sell offers for resources which were subject to mitigation submitted by capacity market sellers that did not pass the test.[9,10,11]

- **Demand-Side and Energy Efficiency Resources.** The 2014/2015 RPM Base Residual Auction was the first auction conducted under the new RPM rules that established two additional demand resource products, Annual DR and Extended Summer DR, along with the implementation of the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement, which define the minimum amount of capacity sought to be procured for each product type.[12] Demand-side resources include demand resources (DR) and energy efficiency (EE) resources cleared in RPM auctions and certified/forecast interruptible load for reliability (ILR). Effective with the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the energy efficiency resource type is eligible to be offered in RPM auctions.[13] Of the 149,974.7 MW of cleared capacity in the 2014/2015 RPM Base Residual Auction, 14,118.4 MW were DR offers and 822.1 MW were EE offers.

6 See "Preliminary Market Structure Screen Results for 2014/2015 RPM Base Residual Auction" (February 1, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf>.
7 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).
8 Effective November 1, 2009, DR and EE resources are not included in the TPS test. See 129 FERC ¶ 61,081 (2009) at P 31.
9 OATT Attachment DD (Reliability Pricing Model) § 6.5.
10 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.
11 The definition of planned generation capacity resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).
12 See 134 FERC ¶ 61,066 (2011).
13 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Market Performance

2014/2015 RPM Base Residual Auction

- **RTO.** There were 160,486.3 MW offered into the 2014/2015 RPM Base Residual Auction. Cleared volumes in the RTO were 149,974.7 MW. The RTO clearing price for Limited Resources was $125.47 per MW-day. The Extended Summer Resource Requirement was a binding constraint, resulting in an RTO clearing price for Extended Summer Resources and Annual Resources of $125.99 per MW-day.

  Cleared capacity resources across the entire RTO will receive a total of $7.3 billion based on the unforced MW cleared and the prices in the 2014/2015 RPM Base Residual Auction.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd increased from 7.8 percent in the first six months of 2010 to 7.9 percent in the first six months of 2011.[14]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 84.3 percent in the first six months of 2010 to 82.2 percent in the first six 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 six months of 2011, 9.8 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.

14 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 six months ending June 30, as downloaded from the PJM GADS database on July 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 Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in the first six 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 six 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.[15,16,17,18,19]

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

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

17 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>.

18 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>.

19 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 5-2 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 5-3 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 5-4 RSI results: 2011/2012 through 2014/2015 RPM Auctions[20] (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	0.60	25	25
EMAAC	0.00	2	2
2013/2014 BRA			
RTO	0.59	87	87
MAAC/SWMAAC	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.00	2	2
Pepco	0.00	1	1
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

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

Demand-Side Resources

Table 5-5 RPM load management statistics by LDA: June 1, 2010 to June 1, 2014[21,22] (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	9,281.9	5,871.1	2,461.3			547.3
EE cleared	679.4	152.0	23.9			35.8
DR net replacements	0.0	0.0	0.0			0.0
EE net replacements	0.0	0.0	0.0			0.0
RPM load management @ 01-June-2013	9,961.3	6,023.1	2,485.2			583.1
DR cleared	14,118.4	7,236.8	1,185.1		443.3	
EE cleared	822.1	199.6	9.8		0.0	
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-2014	14,940.5	7,436.4	1,194.9		443.3	

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 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 5-6 RPM load management cleared capacity and ILR: 2007/2008 through 2014/2015[23,24] (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	8,977.8	9,281.9	658.5	679.4	0.0	0.0
2014/2015	13,663.8	14,118.4	796.9	822.1	0.0	0.0

Table 5-7 RPM load management statistics: June 1, 2007 to June 1, 2014[25,26] (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)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,575.9	10,941.0	(1,218.1)	(1,260.2)	0.2	0.2	9,358.0	9,681.0
01-Jun-12	8,066.8	8,330.2	0.0	0.0	0.0	0.0	8,066.8	8,330.2
01-Jun-13	9,636.3	9,961.3	0.0	0.0	0.0	0.0	9,636.3	9,961.3
01-Jun-14	14,460.7	14,940.5	0.0	0.0	0.0	0.0	14,460.7	14,940.5

23 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.
24 FRR committed load management resources are not included in this table.
25 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.
26 FRR committed load management resources are not included in this table.

Market Performance

Table 5-8 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
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 5-9 RPM revenue by type: 2007/2008 through 2014/2015[27,28] (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	$540,278,140	$666,313,051	$1,692,805,686
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,334,802	$18,323,569	$38,571,074	$68,369,257
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	$1,022,993,505	$1,845,819,870	$2,420,481,808	$2,662,434,386	$1,595,707,479	$1,015,994,058	$1,720,750,315	$1,827,519,210	$14,111,700,631
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	$1,513,684,486	$1,949,325,477	$2,325,941,789	$2,631,948,105	$1,607,096,301	$1,116,743,821	$1,885,036,661	$2,003,810,846	$15,033,587,486
Gas new/reactivated	$3,848,872	$10,071,553	$30,531,957	$58,454,021	$98,670,123	$76,551,231	$165,431,441	$184,029,455	$627,588,652
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,085,726	$308,348,743	$328,877,767	$2,399,355,074
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$0	$6,591,114	$6,602,511
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,367	$1,341,583,669	$1,459,911,217	$10,279,269,415
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	$619,307,680	$433,317,895	$4,073,640,096
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	$43,611,119	$34,529,047	$276,389,711
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	$947,905	$2,371,155	$4,621,747
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,321,010	$1,491,563	$10,138,933
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$4,998,533	$11,859,958	$30,987,962	$82,752,385
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	$6,708,567,045	$7,258,389,284	$49,463,931,934

27 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.
28 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[29] (See 2010 SOM, Figure 5-1)

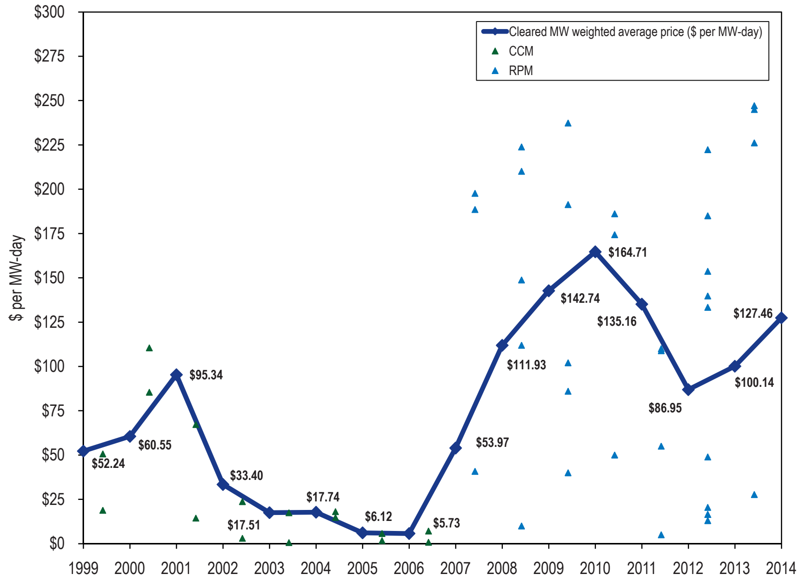


Table 5-10 RPM cost to load: 2011/2012 through 2014/2015[30,31,32] (See 2010 SOM, Table 5-16)

	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	$27.73	85,918.0	$869,614,741
MAAC	$223.85	23,944.0	$1,956,350,506
EMAAC	$240.41	38,634.3	$3,390,146,303
Pepco	$236.93	7,996.7	$691,550,218
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

29 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.

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

31 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.

32 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.

2014/2015 RPM Base Residual Auction

RTO

Table 5-11 RTO offer statistics: 2014/2015 RPM Base Residual Auction[33] (See 2010 SOM, Table 5-19)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	183,007.5	173,033.4		
DR capacity	20,608.1	21,295.9		
EE capacity	806.5	831.8		
Total internal RTO capacity	204,422.1	195,161.1		
FRR	(33,612.7)	(32,060.2)		
Imports	7,620.2	7,060.4		
RPM capacity	178,429.6	170,161.3		
Exports	(1,230.1)	(1,216.3)		
FRR optional	(2,545.7)	(2,534.2)		
Excused generation	(692.5)	(692.3)		
Excused DR and EE	(5,063.6)	(5,232.2)		
Available	168,897.7	160,486.3	100.0%	100.0%
Generation offered	153,048.1	144,108.8	90.6%	89.8%
DR offered	15,043.1	15,545.6	8.9%	9.7%
EE offered	806.5	831.9	0.5%	0.5%
Total offered	168,897.7	160,486.3	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	156,796.5	149,689.8	92.8%	93.3%
Cleared in LDAs	320.5	284.9	0.2%	0.2%
Total cleared	157,117.0	149,974.7	93.0%	93.5%
Make-whole		112.6	0.0%	0.1%

Table 5-11 continued on next page.

33 Unoffered DR and EE MW include PJM approved DR and EE modifications that were not offered into the auction.

Table 5-11 RTO offer statistics: 2014/2015 RPM Base Residual Auction[33] (See 2010 SOM, Table 5-19) (continued)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Reliability requirement		148,323.1		
Total cleared plus make-whole		150,087.3		
Short-Term Resource Procurement Target		3,708.1		
Net excess/(deficit)		5,472.3		
Resource clearing price for Limited Resources ($ per MW-day)		$125.47		
Resource clearing price for Extended Summer Resources ($ per MW-day)		$125.99		
Resource clearing price for Annual Resources ($ per MW-day)		$125.99		
Preliminary zonal capacity price ($ per MW-day)		$125.94	A	
Base zonal CTR credit rate ($ per MW-day)		$0.00	B	
Preliminary net load price ($ per MW-day)		$125.94	A-B	

Generator Performance

Generator Performance Factors

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

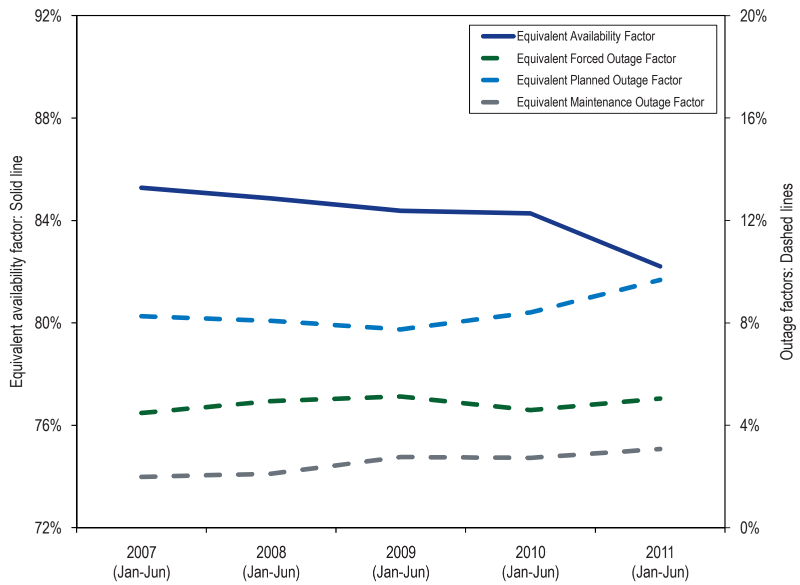
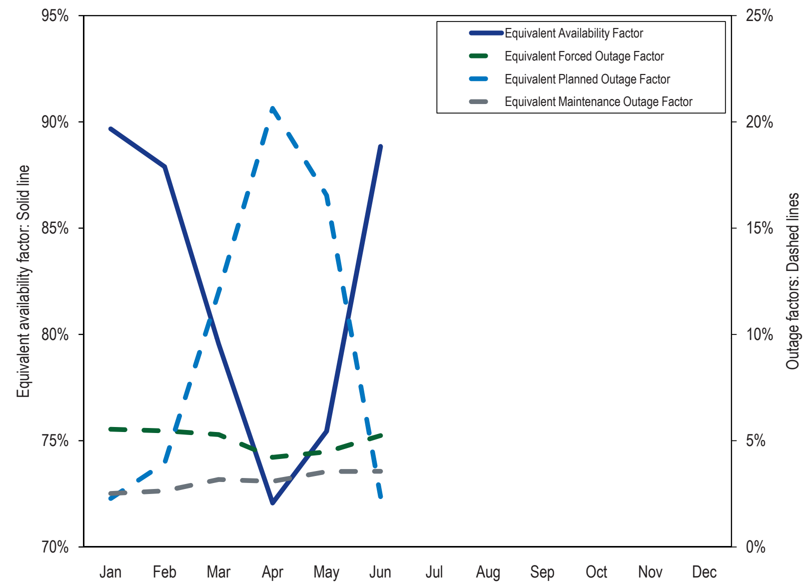
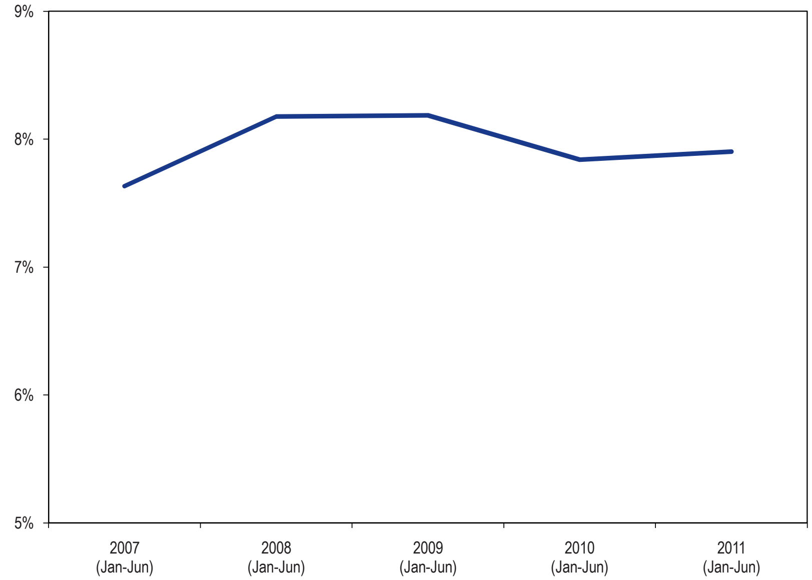


Figure 5-3 Generator performance factors: January through June 2011 (See 2010 SOM, Figure 5-10)



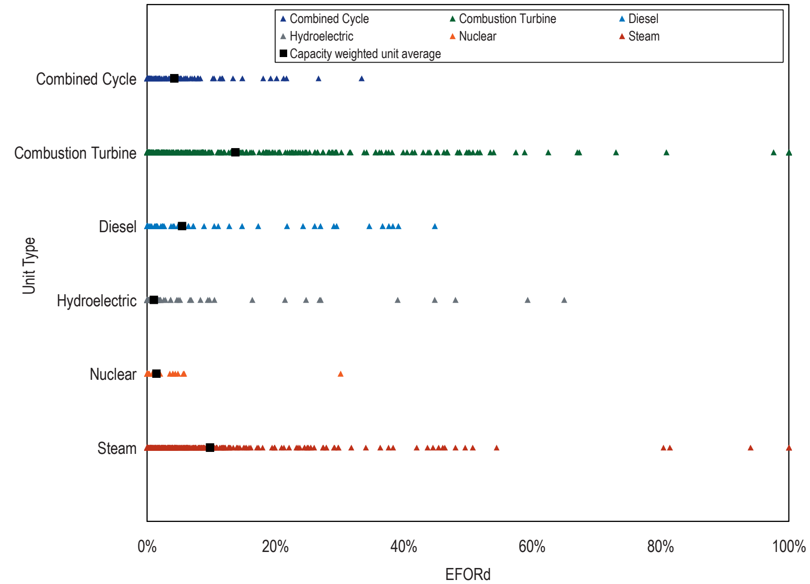
Generator Forced Outage Rates

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



Distribution of EFORd

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



Components of EFORd

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

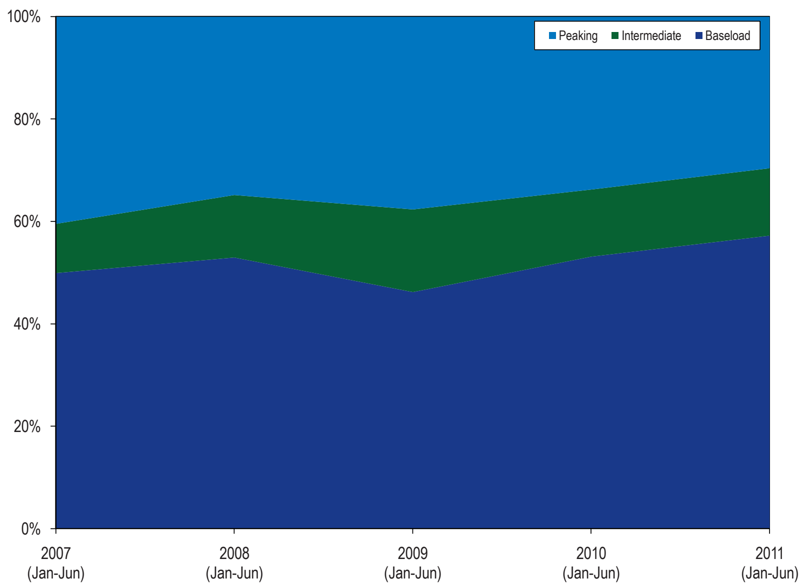
	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)
Combined Cycle	3.8%	3.3%	5.1%	4.2%	3.4%
Combustion Turbine	16.8%	14.1%	10.4%	13.8%	8.1%
Diesel	10.7%	10.1%	8.5%	5.5%	7.1%
Hydroelectric	2.2%	2.1%	2.3%	1.1%	2.3%
Nuclear	1.2%	1.1%	4.0%	1.5%	2.0%
Steam	8.7%	10.6%	10.3%	9.8%	11.5%
Total	7.6%	8.2%	8.2%	7.8%	7.9%

Table 5-13 Contribution to EFORd for specific unit types (Percentage points): January through June 2007 to 2011[34] (See 2010 SOM, Figure 5-21)

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	Change in 2011 from 2010
Combined Cycle	0.4	0.4	0.6	0.5	0.4	(0.1)
Combustion Turbine	2.6	2.2	1.6	2.2	1.3	(0.9)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.0	0.1	0.1
Nuclear	0.2	0.2	0.7	0.3	0.4	0.1
Steam	4.2	5.3	5.1	4.8	5.7	0.9
Total	7.6	8.2	8.2	7.8	7.9	0.1

Duty Cycle and EFORd

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



34 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 June 2011 (See 2010 SOM, Table 5-22)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	5.9%	0.0%	0.0%	0.0%	0.0%	27.1%	22.9%
Economic	1.1%	9.3%	0.0%	2.0%	0.0%	8.3%	7.4%
Generator	3.5%	1.4%	1.1%	1.6%	0.0%	8.4%	7.3%
Electrical	13.3%	17.0%	1.5%	23.5%	11.3%	4.2%	5.8%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	6.2%	5.2%
Boiler Piping System	21.6%	0.0%	0.0%	0.0%	0.0%	3.5%	4.2%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%	4.0%
Feedwater System	2.5%	0.0%	0.0%	0.0%	0.0%	4.0%	3.5%
Miscellaneous (Generator)	15.3%	3.9%	1.5%	0.1%	5.2%	1.8%	2.8%
Circulating Water Systems	1.6%	0.0%	0.0%	0.0%	12.3%	2.0%	2.5%
Fuel Quality	0.0%	0.0%	1.4%	0.0%	0.0%	2.5%	2.1%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	33.4%	0.0%	2.0%
Auxiliary Systems	4.4%	24.3%	0.0%	0.3%	0.0%	1.0%	2.0%
Cooling System	0.0%	0.0%	0.4%	0.6%	4.5%	1.9%	1.9%
Controls	1.6%	1.3%	0.5%	0.5%	10.9%	1.0%	1.6%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	1.5%
Miscellaneous (Steam Turbine)	1.0%	0.0%	0.0%	0.0%	0.6%	1.7%	1.5%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	1.4%
Stack Emission	0.0%	6.5%	0.0%	0.0%	0.0%	1.4%	1.4%
All Other Causes	27.9%	36.4%	93.5%	71.5%	21.9%	16.8%	19.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

	Contribution to Economic Reasons
Lack of fuel (OMC)	96.8%
Lack of fuel (Non-OMC)	1.9%
Other economic problems	0.8%
Lack of water (Hydro)	0.3%
Fuel conservation	0.2%
Total	100.0%

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

	EFOF	Contribution to EFOF
Combined Cycle	2.8%	5.7%
Combustion Turbine	1.9%	3.6%
Diesel	3.8%	0.1%
Hydroelectric	0.6%	1.1%
Nuclear	1.2%	5.9%
Steam	7.5%	83.5%
Total	4.6%	100.0%

Outages Deemed Outside Management Control

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

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Economic	72.7%	7.2%
Catastrophe	12.8%	1.3%
Electrical	8.5%	0.8%
Power Station Switchyard	2.9%	0.3%
Miscellaneous (External)	2.8%	0.3%
Fuel Quality	0.4%	0.0%
Regulatory	0.0%	0.0%
Total	100.0%	9.8%

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

	EFORd	XEFORd	Difference
Combined Cycle	3.4%	3.2%	0.1%
Combustion Turbine	8.1%	6.1%	2.1%
Diesel	7.1%	3.7%	3.5%
Hydroelectric	2.3%	2.0%	0.3%
Nuclear	2.0%	1.9%	0.1%
Steam	11.5%	10.2%	1.3%
Total	7.9%	6.9%	1.0%

Components of EFORp

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

	2010 (Jan-Jun)	2011 (Jan-Jun)
Combined Cycle	0.5	0.2
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.0	0.1
Nuclear	0.3	0.5
Steam	3.4	3.3
Total	4.6	4.5

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

	2010 (Jan-Jun)	2011 (Jan-Jun)
Combined Cycle	4.3%	1.8%
Combustion Turbine	2.5%	2.7%
Diesel	3.9%	2.5%
Hydroelectric	0.5%	2.6%
Nuclear	1.5%	2.7%
Steam	6.8%	6.6%
Total	4.6%	4.5%

EFORd, XEFORd and EFORp

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

	EFORd	XEFORd	EFORp
Combined Cycle	0.4	0.4	0.2
Combustion Turbine	1.3	1.0	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1
Nuclear	0.4	0.3	0.5
Steam	5.7	5.1	3.3
Total	7.9	6.9	4.5

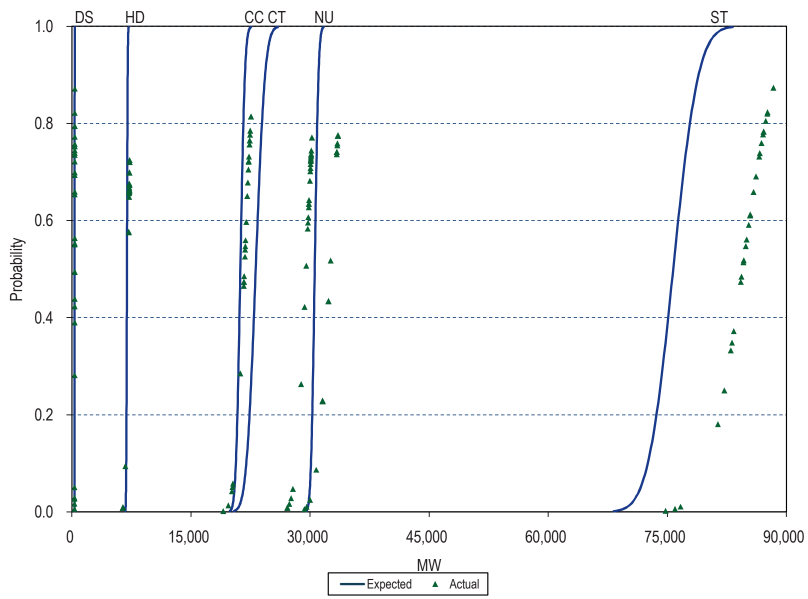
Table 5-22 PJM EFORd, XEFORd and EFORp data by unit type: January through June 2011[35] (See 2010 SOM, Table 5-30)

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.4%	3.2%	1.8%	0.1%	1.5%
Combustion Turbine	8.1%	6.1%	2.7%	2.1%	5.4%
Diesel	7.1%	3.7%	2.5%	3.5%	4.7%
Hydroelectric	2.3%	2.0%	2.6%	0.3%	(0.3%)
Nuclear	2.0%	1.9%	2.7%	0.1%	(0.7%)
Steam	11.5%	10.2%	6.6%	1.3%	4.9%
Total	7.9%	6.9%	4.5%	1.0%	3.4%

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

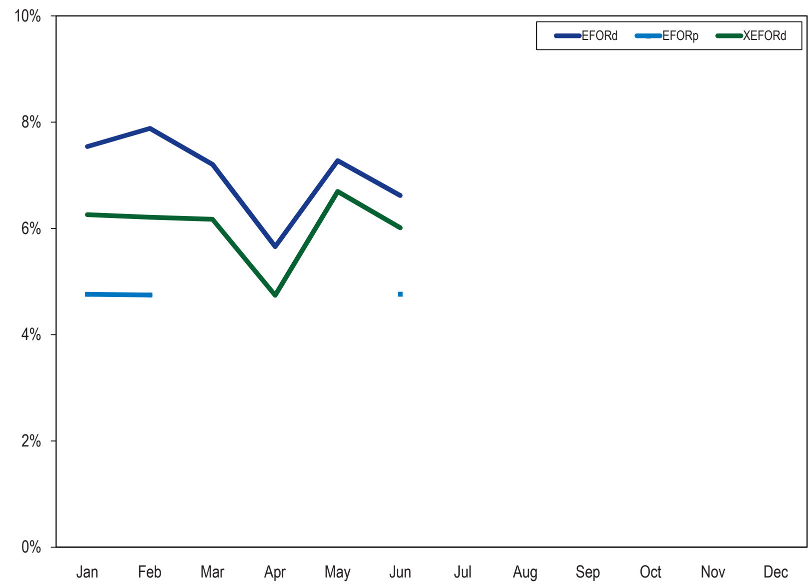
Comparison of Expected and Actual Performance

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



Performance by Month

Figure 5-8 EFORd, XEFORd and EFORp: January through June 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 2010.

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 six 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 94 percent of the hours in the first six 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.

- Participant behavior was evaluated as competitive because the market rules require 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 by offer capping those suppliers.

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 five 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 regulation market clearing price for the first six months of 2011 was $15.53, 13 percent lower than the $17.76 price for the first six months of 2010. Regulation total costs per MW for the first six months of 2011 were $30.89, an increase of 3 percent from the $30.05 total cost in the first six months of 2010. For the first six months of 2011 the total cost of regulation per MW was 101 percent higher than the market clearing price. For the first six months of 2010 the total cost of regulation was 67 percent higher than the market clearing price.

  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 at the direction of PJM Dispatch as a result of binding constraints or performance problems.

- Total self-scheduled regulation MW in the first six months of 2011 was 16 percent of all regulation, a decrease from 20 percent in the first six months of 2010.

- Of the LSEs' obligation to provide regulation during the first six months of 2011, 81 percent was purchased in the spot market, 16 percent was self scheduled, and three percent was purchased bilaterally.

- The load weighted synchronized reserve market price in the first six months of 2011 was $12.18 per MWh, $3.26 higher than the price during the first six months of 2010. The total cost of synchronized reserves per MWh during the first six months of 2011 was $15.72, a 30 percent increase over the cost of synchronized reserves ($12.13) during the same period of 2010. The cost to price ratio of synchronized reserve during the first six months of 2011 was 129 percent, a decrease from the cost to price ratio of 136 percent in the first six months 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.

- In December of 2010, PJM Market Operations changed the Tier 1 synchronized reserve transfer capacity across the AP South interface from 15 percent of available Tier 1 to five percent.[5] 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 April 2011. In May, 2011, the implementation of the new TrAIL line made Bedington – Black Oak the most restrictive constraint rather than AP South. This allowed more Tier 1 to become available. PJM increased the reserve transfer capacity several times to its current 30 percent. As a result the amount of Tier 2 required dropped in May and significantly in June.

- The load weighted price of DASR in the first six months of 2011 was $0.44 per MW. In the first six months of 2010, the load weighted price of DASR was $0.06 per MW. The increase in average DASR price was caused by several days of high DASR prices in early June, which were primarily the result of opportunity costs, which were a function of high LMPs.

- Black start zonal charges in the first six months of 2011 ranged from $0.02 per MW in the Pepco zone to $0.66 per MW in the PPL zone.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through June*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations. In addition, the MMU recommends that the Synchronized Reserve Market design, including compliance monitoring and non-compliance penalties, 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.

Overview

Regulation Market

The PJM Regulation Market in the first six months of 2011 continued to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, 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.[6]

Market Structure

- **Supply.** In the first six 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 six months of 2011. The ratio of eligible regulation offered to regulation required averaged 2.95 for the first six months of 2011. This is a two percent decrease over the first six months of 2010 when the ratio was 3.01.

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

6 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

- **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 six months of 2011 was 874 MW (798 MW off peak, and 959 MW on peak). This is a 13 MW increase in the average hourly regulation demand for the first six months of 2010 (792 MW off peak, and 936 MW on peak).

- **Market Concentration.** During the first six months of 2011, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1720 which is classified as "moderately concentrated."[7] 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 86 percent of all hours had a maximum market share greater than 20 percent.[8] In the first six months of 2011, 94 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 six months of 2011 was characterized by structural market power in 94 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit 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.[9] 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.** For the PJM Regulation Market in the first six months of 2011, the load weighted, average price per MW (the Regulation Market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $15.53 per MW. This was a decrease of $2.23, or 13 percent, from the average price for regulation during the same period in 2010. The total cost of regulation increased by $0.84 from $30.05 per MW for the first six months of 2010, to $30.89, or three percent. The Regulation Market clearing price was only 50 percent of the total regulation cost per MW. This 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.

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).

PJM made no changes to the Synchronized Reserve Market structure during the first six months of 2011. The integration of the Trans-Allegheny Line (TrAIL)[10] project (performed in three stages April 8, May 13, and May 20, 2011) requires a change in the near future. The interface defining the eastern subzone of the RFC Synchronized Reserve Market has been the AP South interface since March 2009. [11] TrAIL increased the limit of AP South, allowing more Tier 1 MW to be available to the east. As a result, Bedington – Black Oak is now the most limiting interface. This change will be made to PJM's Manual 11, Energy and Ancillary Services Market Operations in its next revision. Without changing the interface, PJM made frequent changes to the Tier 1 transfer capability of the AP South interface throughout late April and early May. The transfer capability changed from

7 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.

8 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.

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

10 http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/trail.aspx

11 See PJM. "PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 46 (June 1, 2011)p. 67.

15 percent, where it had been set throughout most of 2010 to 30 percent. It was then set to 50 percent, then back down to 30 percent, 10 percent and 20 percent. From May 20, 2011, through the end of June the transfer percentage was set to 30 percent. The interface transfer capability is a parameter (changeable by PJM Market Operations) specifying the percent of Tier 1 synchronized reserve west of the most limiting interface that can be considered available to the Mid-Atlantic Subzone. The more Tier 1 synchronized reserve available, the less Tier 2 synchronized reserve needs to be cleared. These changes to the transfer interface capability 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 three percent of all synchronized reserves during the first six months of 2011, down from six percent for the same time period in 2010. Opportunity cost payments accounted for 22 percent of total costs during the first six months of 2011 compared to 19 percent for the first six months of 2010.

Market Structure

- **Supply.** In the first six months of 2011 the offered and eligible excess supply ratio was 1.03 for the Mid-Atlantic Subzone.[12] For the first six months of 2010 the offered and eligible excess supply ratio in the Mid Atlantic subzone was 1.21. For the RFC zone, the offered and eligible excess supply ratio was 3.02. For the first six months of 2010 the offered and eligible excess supply ratio in the RFC zone was 2.33. 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. 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.

- **Demand.** PJM made several changes to the hourly required synchronized reserve requirements between December, 2008 and June, 2011 (Table 6-4). 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.

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

Table 6-4 Synchronized Reserve Market required MW, RFC zone and Mid-Atlantic subzone, December, 2008 through June 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	Jun 2011	1,300	Mar 2010	Jun 2011	1,350

For the first six months of 2011, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 86 percent of hours. In the first six months of 2010 a Tier 2 synchronized reserve market was cleared in 78 percent of hours. For the first six months of 2011, the average required Tier 2 synchronized reserve (including self scheduled) was 560 MW. For the first six months of 2010 the average required Tier 2 synchronized reserve was 358 MW. The Tier 2 requirement for January through March of 2011, was 756 MW but only 372 MW for April through June of 2011. This drop was primarily because TrAIL increased the transfer capacity of the most constraining interface allowing more Tier 1 to be available in the Mid Atlantic Subzone from the west.

Synchronized reserves added out of market were three percent of all Mid-Atlantic Subzone synchronized reserves in the first six months of 2011. Synchronized reserves added out of market were also three percent of all Mid-Atlantic Subzone synchronized reserves in the first six 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 (9 hours) cleared a Tier 2 Synchronized Reserve Market in the RFC during the first six months of 2011. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone in eleven hours during the first six months of 2011.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone for the first six months of 2011 was 2616, which is classified as "highly concentrated."[13] For purchased synchronized reserve (cleared plus

13 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).

added) the HHI was 2674. In the first six months of 2011, 45 percent of hours had a maximum market share greater than 40 percent, compared to 58 percent of hours in the same period of 2010.

In the Mid-Atlantic Subzone, in the first six months of 2011, 68 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In the same period of 2010, 45 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 six 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 demand side resources increased in the first six months of 2011 over the first six months of 2010 (from 315,179 MW to 449,377 MW) but their share of the total Synchronized Reserve Market declined from 21 percent to 19 percent. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in five percent of hours in the first six months of 2011 compared to nine percent of hours on the first six months of 2010.

- **Compliance.** There is a compliance issue in the Synchronized Reserve Market. A substantial proportion of the resources which offer and clear synchronized reserve fail to provide synchronized reserve when an actual spinning event occurs, and are penalized as a result. The problem exists for both demand side resources and generating resources. 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 $12.18 per MW in the first six months of 2011, a $3.58 per MW increase from the same period in 2010. The market clearing price was 77 percent of the total synchronized reserve cost per MW in the first six months of 2011, up from 74 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 six months of 2011.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[14] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[15] 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 six months of 2011, there were 11 hours in the DASR market which failed the three pivotal supplier test. All 11 hours occurred in June during periods of high demand (above 7,500 MW). The current structure of PJM's DASR Market does not include

14 See 117 FERC ¶ 61,331 (2006).
15 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 six 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.[16] 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 6,089 MW per hour for the first six months of 2011, an increase from 5,850 MW per hour during the same period in 2010.

Market Conduct

- **Withholding.** 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 cost. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[17] Units that do not offer will have their offers set to zero.

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

Market Performance

- **Price.** In the first six months of 2011, the load weighted price of DASR was $0.44 per MW. In the first six months of 2010, the load weighted price of DASR was $0.06 per MW. DASR prices were high during the first ten days of June, when DASR prices at times exceeded $100. The high prices were primarily the result of opportunity costs, which were a function of high LMPs.

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.[18]

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 six months of 2011, charges were $6.10 million. This is 30 percent higher than the first six months of 2010, when total black start service charges were $4.70 million. There was substantial zonal variation. The increased cost of black start in 2011 is attributable to updated Schedule 6A rates for all units. The increased Schedule 6A rates included net cost of new entry, VOM, bond rates, and oil forward strip.[19]

Ancillary Services costs per MW of load: 2001 - 2011

Table 6-5 shows PJM ancillary services costs from January through June 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.

16 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
17 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 46 (June 1, 2011), p. 124.
18 OATT Schedule 1 § 1.3BB.
19 http://www.pjm.com/~/media/committees-groups/task-forces/bsstf/20100420/20100420-automated-formula-rate-adjustment-process.ashx

Table 6-5 History of ancillary services costs per MW of Load: January through June 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-Jun)	$0.50	$0.45	$0.22	$0.00	$1.18
2002 (Jan-Jun)	$0.37	$0.55	$0.23	$0.00	$0.59
2003 (Jan-Jun)	$0.57	$0.61	$0.24	$0.14	$0.81
2004 (Jan-Jun)	$0.53	$0.66	$0.26	$0.16	$0.93
2005 (Jan-Jun)	$0.57	$0.51	$0.27	$0.11	$0.60
2006 (Jan-Jun)	$0.48	$0.48	$0.29	$0.08	$0.32
2007 (Jan-Jun)	$0.61	$0.46	$0.30	$0.09	$0.50
2008 (Jan-Jun)	$0.73	$0.37	$0.30	$0.08	$0.66
2009 (Jan-Jun)	$0.37	$0.43	$0.37	$0.04	$0.50
2010 (Jan-Jun)	$0.37	$0.38	$0.36	$0.06	$0.75
2011 (Jan-Jun)	$0.33	$0.36	$0.41	$0.11	$0.79

Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.[20] 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. 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.

20 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."

The MMU concludes that the DASR Market results were competitive in the first six 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 six months of 2011 as a result of the identified 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 six months of 2011. The MMU concludes that the DASR Market results were competitive in the first six months of 2011.

Regulation Market

Market Structure

Supply

Table 6-6 PJM regulation capability, daily offer[21] and hourly eligible: January through June 2011 (See 2010 SOM, Table 6-5)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered (MW)	Average Hourly Eligible (MW)	Percentage of Capability Eligible
All Hours	8,764	5,812	66%	2,566	29%
Off Peak	8,764			2,323	27%
On Peak	8,764			2,834	32%

21 Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.

Demand

Table 6-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through June 2011 (See 2010 SOM, Table 6-6)

Month	Average Required Regulation	Ratio of Supply To Requirement
Jan	960	3.19
Feb	897	3.06
Mar	823	3.02
Apr	748	2.88
May	786	2.84
Jun	1,036	2.73

Market Concentration

Table 6-8 PJM cleared regulation HHI: January through June 2011 (See 2010 SOM, Table 6-7)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, January through June, 2011	818	1720	3683

Figure 6-1 PJM Regulation Market HHI distribution: January through June 2011 (See 2010 SOM, Figure 6-1)

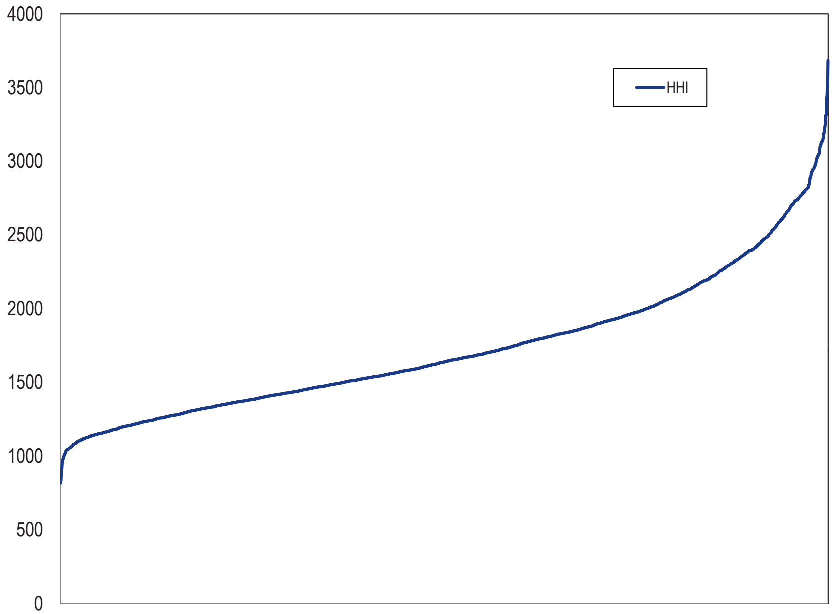


Table 6-9 Highest annual average hourly Regulation Market shares: January through June, 2011 (See 2010 SOM, Table 6-8)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	25%
2	16%
3	15%
4	10%
5	9%

Table 6-10 Regulation market monthly three pivotal supplier results: January through June, 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	80%

Market Conduct

Offers

Figure 6-2 Off peak and on peak regulation levels: January through June, 2011 (See 2010 SOM, Figure 6-2)

Table 6-11 Regulation sources: spot market, self-scheduled, bilateral purchases: January through June, 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

Market Performance

Price

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): January through June, 2011 (See 2010 SOM, Figure 6-3)

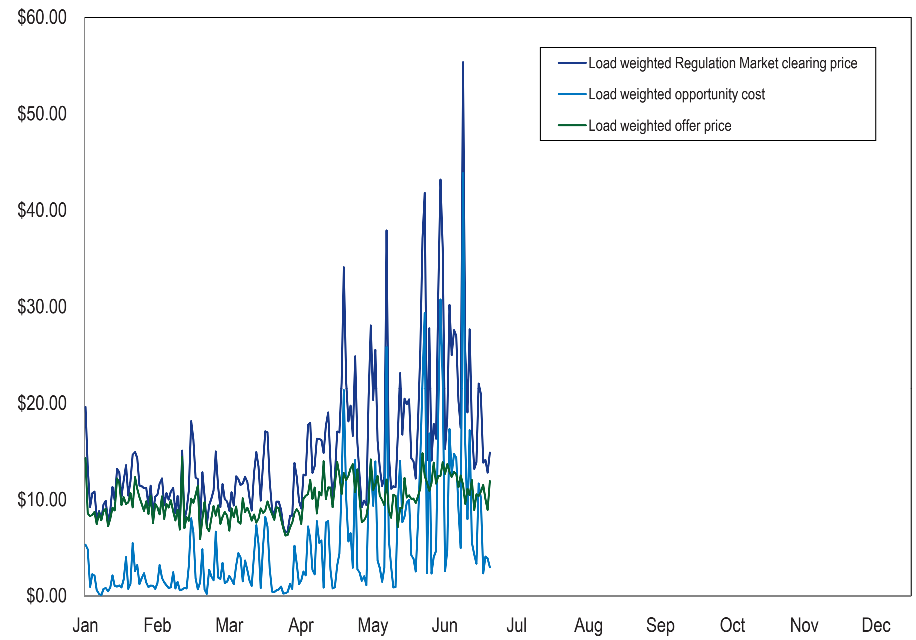


Figure 6-4 Monthly average regulation demand (required) vs. price: January through June, 2011 (See 2010 SOM, Figure 6-4)

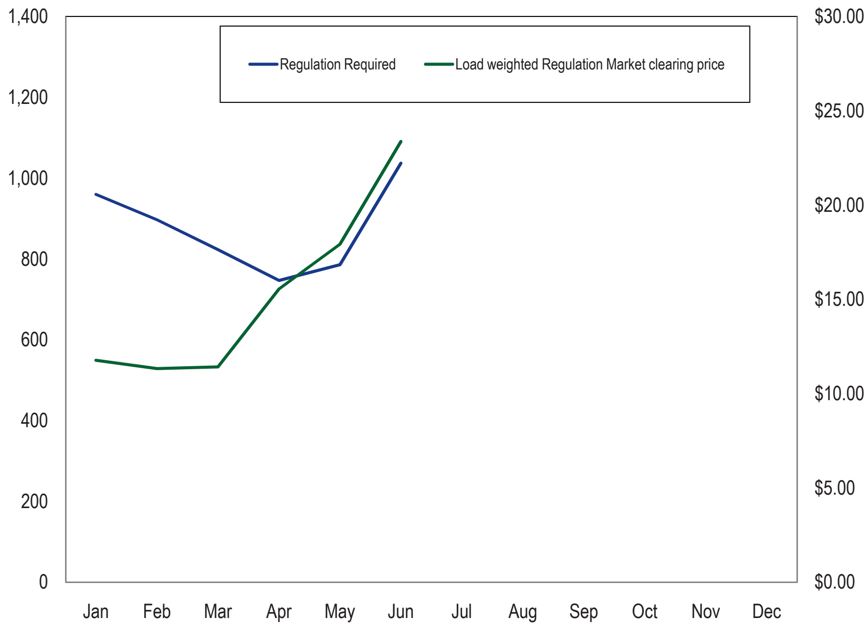


Figure 6-5 Monthly load weighted, average regulation cost and price: January through June, 2011 (See 2010 SOM, Figure 6-5)

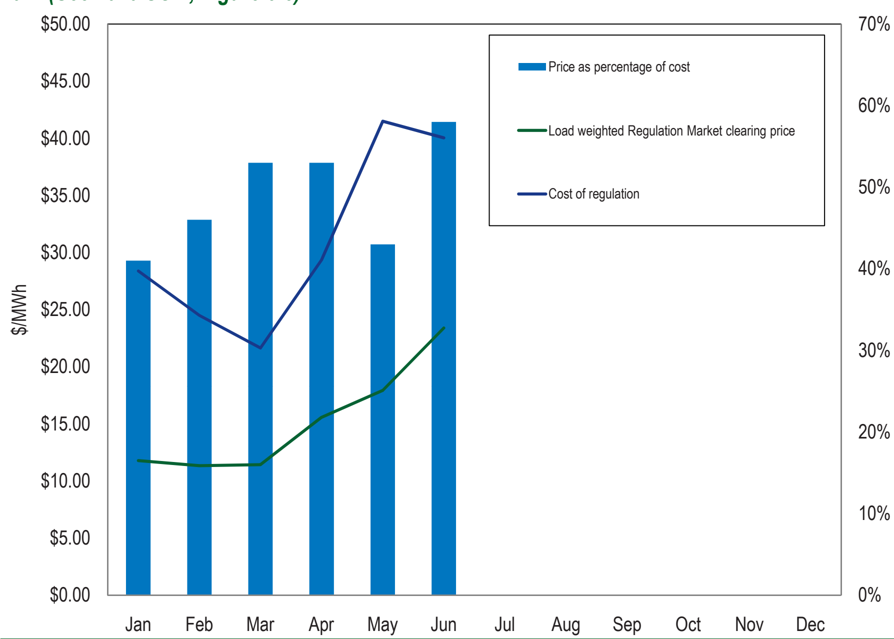


Table 6-12 Total regulation charges: January through June, 2011 (See 2010 SOM, Table 6-11)

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load 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	$23.64	$40.04

Table 6-13 Comparison of load weighted price and cost for PJM Regulation, August 2005 through June 2011[22] (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	$15.53	$30.89	50%

22 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.

Analysis of Regulation Market Changes

Table 6-14 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.

Increase Offer Margin from $7.50 to $12.00

Table 6-15 Impact of $12 adder to cost based regulation offer: December 2008 through June 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%

Table 6-15 continued on 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	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%
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%
Total				$606,435,206	$7,712,516	1.3%

Eliminate Offset Against Balancing Operating Reserves Credits

Table 6-16 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through June 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%
Total		$3,568,704	$606,435,244	0.6%

Table 6-16 continued on next column.

Synchronized Reserve Market

Market Structure

Demand

Figure 6-6 Mid-Atlantic Subzone average hourly synchronized reserve supplied by Tier 1 estimate and Tier 2 scheduled: January through June, 2011 (See 2010 SOM, Figure 6-7)

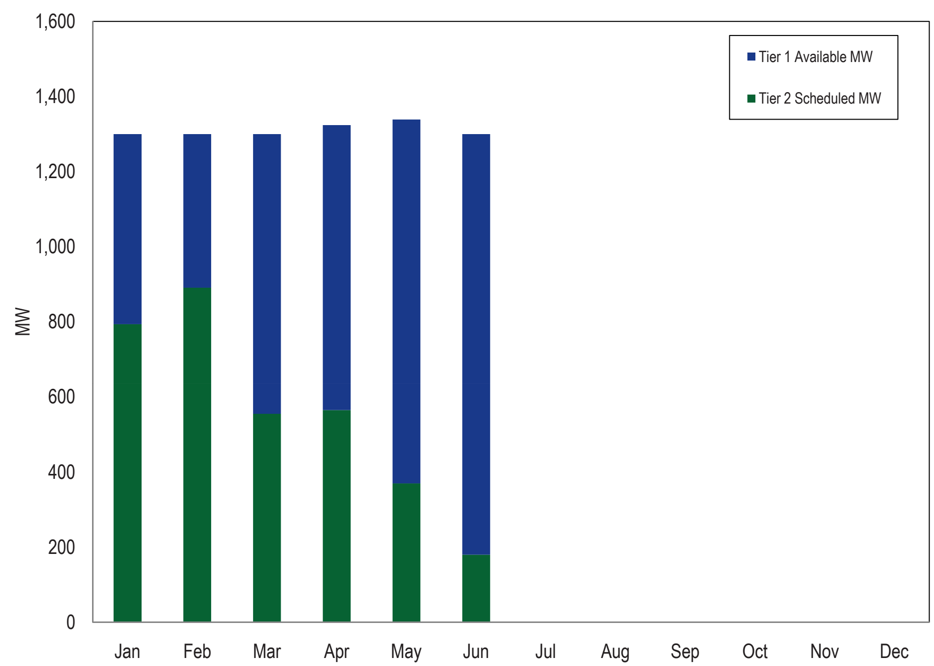
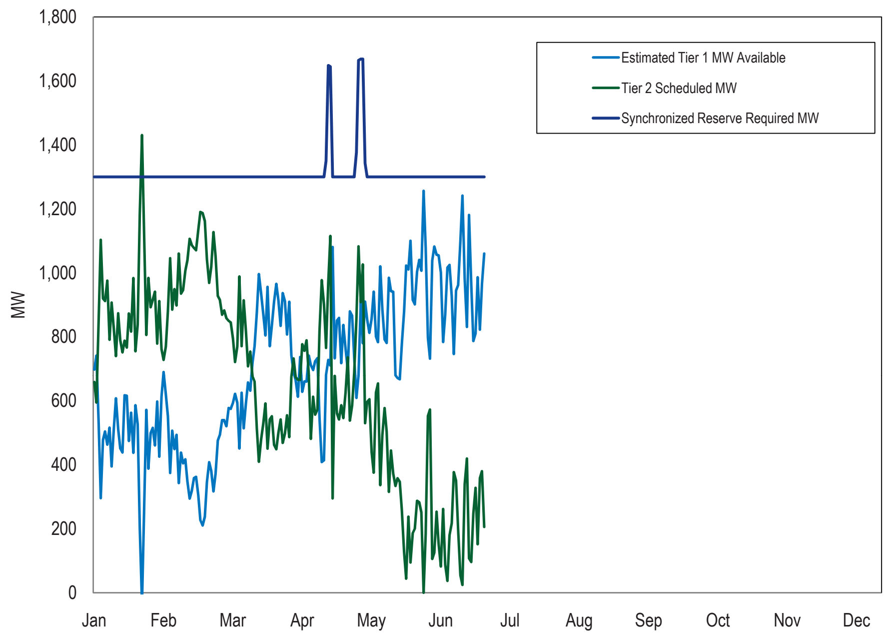


Figure 6-7 Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through June, 2011 (See 2010 SOM, Figure 6-8)



Market Concentration

Table 6-17 Mid-Atlantic Subzone Tier 2 Synchronized Reserve Market cleared market shares: January through June, 2011 (See 2010 SOM, Table 6-16)

Company Market Share Rank	Cleared Synchronized Reserve Average Market Share
1	31%
2	31%
3	21%
4	18%
5	16%

Market Conduct

Offers

Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): January through June, 2011 (See 2010 SOM, Figure 6-9)

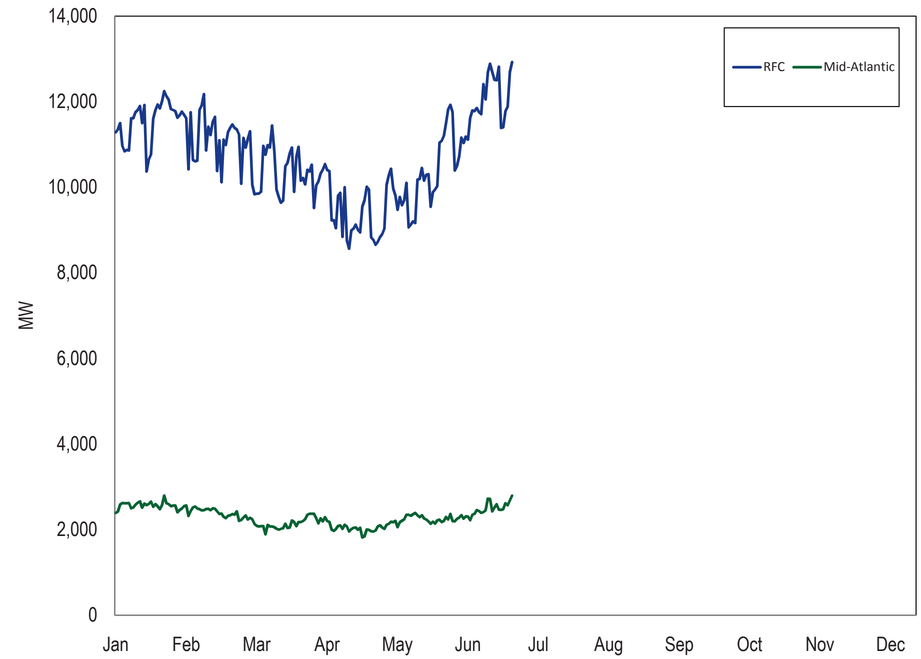
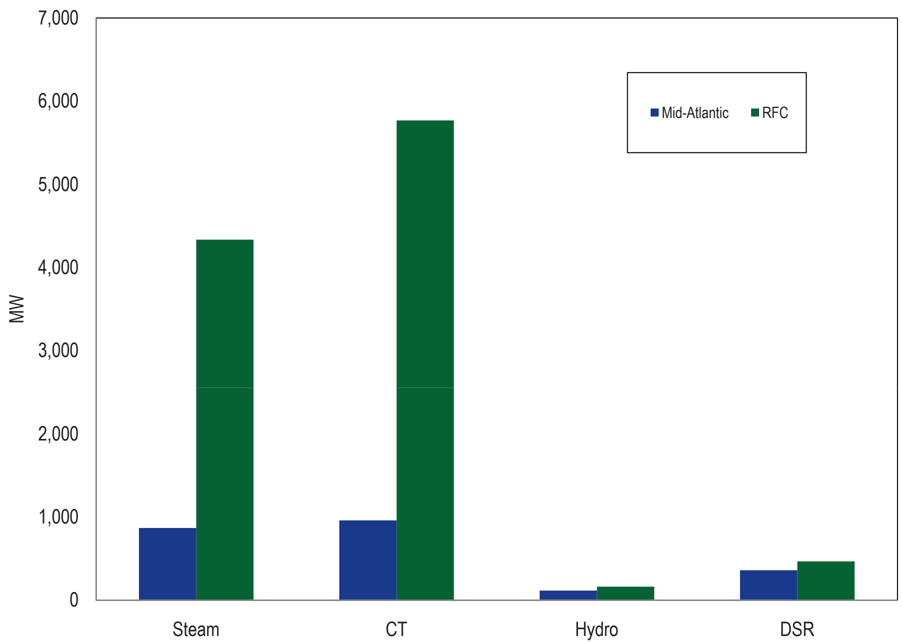


Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through June, 2011 (See 2010 SOM, Table 6-10)



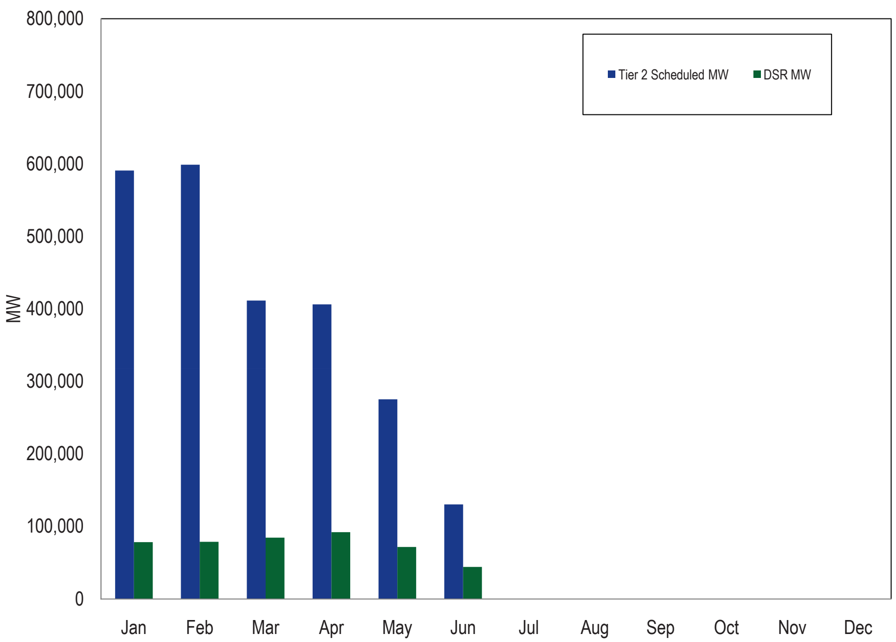
DSR

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 June 2010 and 2011 (See 2010 SOM, Table 6-17)[23]

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%
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%

23 The corresponding table (Table 6-17, p. 166) of the *2011 Quarterly State of the Market Report for PJM: January through March*, included incorrect results for March, 2010 as well as January, February, and March 2011.

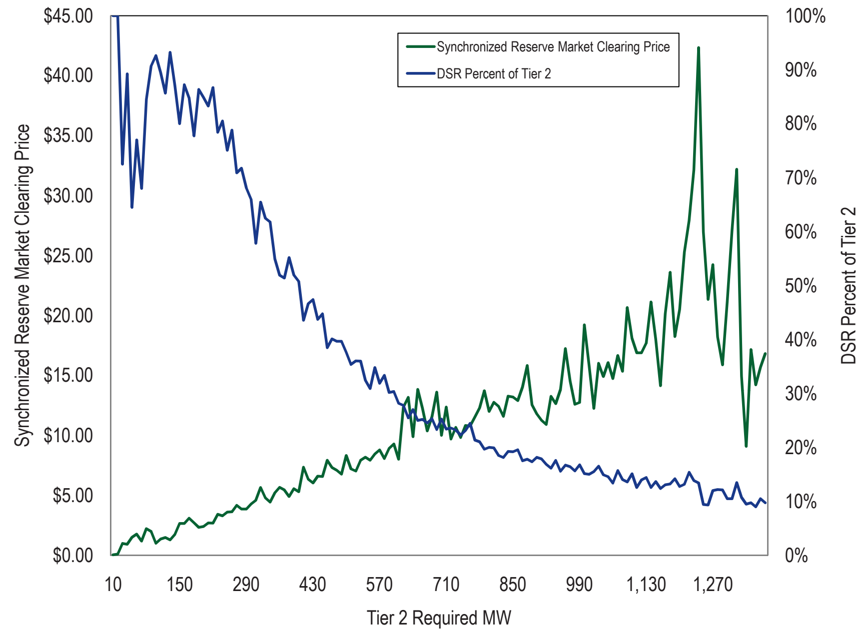
Figure 6-10 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through June, 2011 (See 2010 SOM, Figure 6-11)



Market Performance

Price

Figure 6-11 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: January through June, 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 June, 2011 (See 2010 SOM, Figure 6-13)

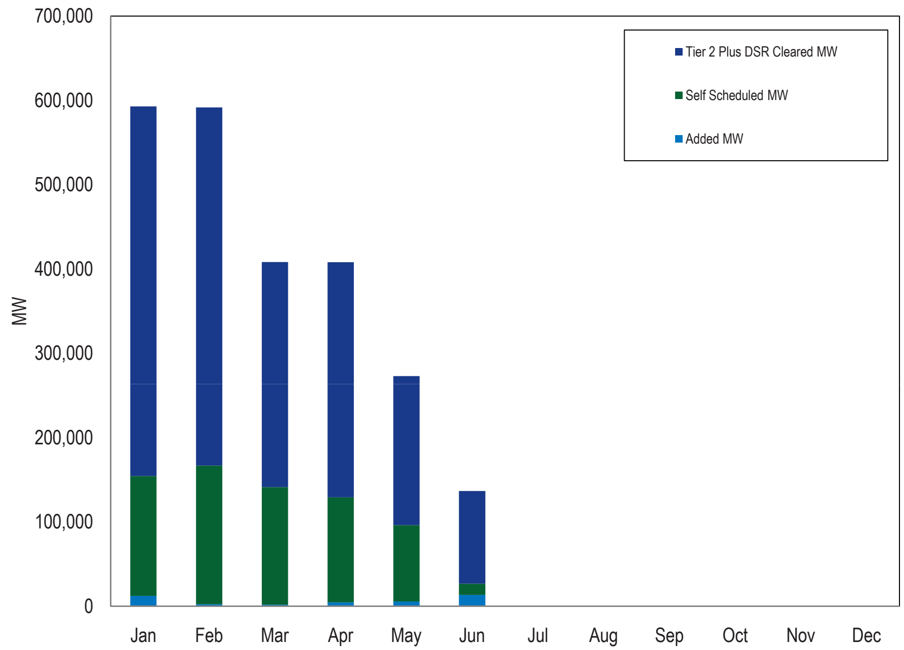


Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the Mid-Atlantic Subzone: January through June, 2011 (See 2010 SOM, Figure 6-14)

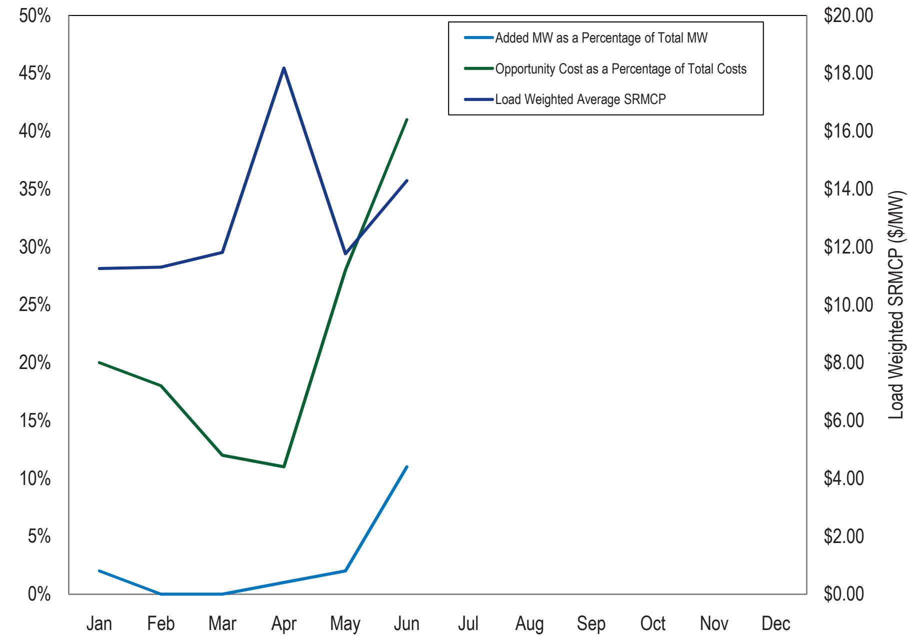


Figure 6-14 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): January through June, 2011 (See 2010 SOM, Figure 6-15)

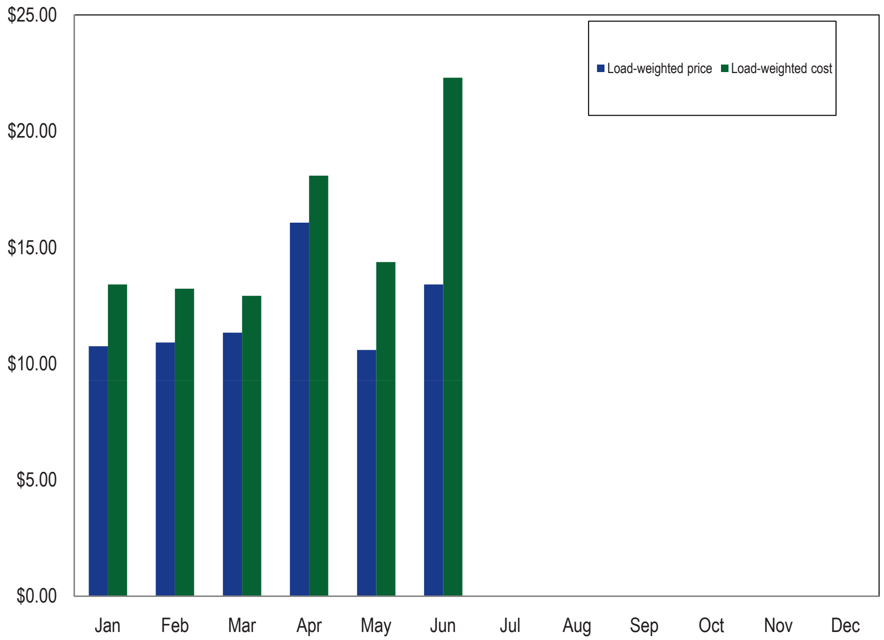


Table 6-19 Comparison of load weighted price and cost for PJM Synchronized Reserve, January through June 2005 through 2011 (See 2010 SOM, Table 6-18)

Year	Load Weighted Synchronized Reserve Market Price	Load Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005 (Jan-Jun)	$11.77	$15.52	76%
2006 (Jan-Jun)	$12.10	$18.25	66%
2007 (Jan-Jun)	$20.08	$22.89	88%
2008 (Jan-Jun)	$11.86	$17.46	68%
2009 (Jan-Jun)	$5.89	$10.15	58%
2010 (Jan-Jun)	$8.92	$12.13	74%
2011 (Jan-Jun)	$12.18	$15.72	77%

Day Ahead Scheduling Reserve (DASR)

Market Performance

Table 6-20 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through June, 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

Black Start Service

Table 6-21 Black start yearly zonal charges for network transmission use: January through June, 2011 (See 2010 SOM, Table 6-21)

Blackstart Zone	Network Charges	Blackstart Rate ($/MW)
AECO	$209,614	$0.39
AEP	$297,578	$0.07
AP	$73,606	$0.05
ATSI	$34,844	$0.03
BGE	$517,321	$0.41
ComEd	$1,997,646	$0.50
DAY	$71,969	$0.12
DPL	$187,900	$0.03
DLCO	$16,817	$0.26
JCPL	$244,020	$0.21
Met-Ed	$232,741	$0.44
PECO	$450,328	$0.28
PENELEC	$177,320	$0.33
Pepco	$157,250	$0.02
PPL	$71,900	$0.66
PSEG	$1,289,520	$0.13
UGI	$71,900	$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 six months of 2011.

Highlights

- Congestion costs in the first six months of 2011 decreased by 13 percent over congestion costs in the first six months of 2010 (Table 7-2).

- Net balancing congestion costs were -$132.6 million in the first six months of 2011 and -$89.4 million in the first six months of 2010. Negative balancing congestion costs indicates that the congestion payments in the Day-Ahead market exceeded congestion payments in the Real-Time market.

- In the first six months of 2011, ComEd was the most congested zone. ComEd accounted for nearly 21 percent of the total congestion cost (Table 7-17). In the first six months of 2010, Dominion was the most congested zone, accounting for nearly 20 percent of the total congestion cost.

- May and June congestion costs were significantly lower compared to 2010 (48.2 percent and 33.2 percent). March congestion costs were substantially higher compared to 2010 (120.8 percent). (Table 7-3).

- PJM backbone projects are a subset of significant baseline 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 February 28, 2011, PJM announced that the Board has decided to hold the Potomac – Appalachian Transmission Highline (PATH) project in abeyance in its 2011 Regional Transmission Expansion Plan (RTEP), but did not direct the sponsoring Transmission Owners to cancel or abandon the PATH project.

  On February 28, 2011, American Electric Power and FirstEnergy Corp., the sponsoring Transmission Owners, announced that they would file to withdraw their applications for state regulatory approval of the PATH.

Recommendations

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

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."

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $83.7 million or 13 percent, from $644.6 million in the first six months of 2010 to $560.9 million in the first six months of 2011. Day-ahead congestion costs decreased by $40.5 million or 5.5 percent, from $733.9 million in the first six months of 2010 to $693.5 million in the first six months of 2011. Balancing congestion costs decreased by $43.2 million or 48.3 percent from -$89.4 million in the first six months of 2010 to -$132.6 million in the first six months of 2011. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were three percent of total PJM billings in the first six months of 2011, which is comparable to the four percent share for calendar year 2010, but lower than the share of total billings from 2003 through 2008. Total PJM billings in the first six months of 2011 were $18.705 billion. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. All metrics associated with ATSI reported in this section represent activity within the month of June 2011.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In the first six 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 six months of 2011 ranged from $35.0 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, the AEP-Dominion interface and the Bedington – Black Oak interface, (Table 7-13). The AP South interface had the effect of increasing prices in eastern and southern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2011.[3] Day-ahead congestion frequency increased by 27.5 percent from 45,432 congestion event hours in the first six months of 2010 to 57,925 congestion event hours in the first six months of 2011. Day-ahead, congestion-event hours decreased on internal PJM interfaces and transmission lines while congestion-event hours increased on transformers and reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (MISO).

  Real-time congestion frequency increased by 3.0 percent from 9,236 congestion event hours in the first six months of 2010 to 9,510 congestion event hours in the first six months of 2011. Real-time, congestion-event hours decreased on the internal PJM interfaces and lines, while congestion-event hours increased on transformers and reciprocally coordinated flowgates between PJM and the MISO.

  The AP South Interface was the largest contributor to congestion costs in the first six months of 2011. With $172 million in total congestion costs, it accounted for 31 percent of the total PJM congestion costs in the first six months of 2011. The top five constraints in terms of congestion costs together contributed $322.6 million, or 57 percent, of the total PJM congestion costs in the first six months of 2011. The top five constraints were the AP South interface, the 5004/5005 interface, the Belmont transformer, the AEP – Dominion interface and the Bedington – Black Oak interface. Facilities were constrained in the Day-Ahead market more frequently than in the real-time market. During the first six months of 2011, among the hours for which a facility is constrained in the day-ahead market, the facilities were also constrained in the real-time market for only 6.6 percent of those hours.

- **Zonal Congestion.** In the first six months of 2011, the ComEd Control Zone experienced the highest congestion costs of the control zones in PJM with $120.9 million. The Crete – St. Johns flowgate, the AP South interface, Electric Junction – Nelson transmission line, the 5004/5005 interface and Bunsonvillle – Eugene flowgate contributed $46.1 million, or 38 percent of the total ComEd Control Zone congestion costs (Table

3 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.

7-56). The AEP Control Zone recorded the second highest congestion cost in PJM in the first six months of 2011. The congestion costs in the AEP Control Zone increased from $76.5 million in the first six months of 2010 to $106.3 million or 38 percent in the first six months of 2011. The AP South interface contributed $24.0 million, or 22.6 percent of the total AEP Control Zone congestion cost in the first six months of 2011. Continuing the trend observed in the first three months of 2011, increases in day-ahead congestion frequency and congestion costs from the AP South interface and the Belmont transformer contributed to the increase in congestion cost in the AEP Control Zone in the first six months of 2011. The AP South interface contributed $28.5 million to the AEP Control Zone congestion costs and the Belmont transformer contributed $28.4 million to the AEP Control Zone congestion costs.

- **Ownership.** In the PJM market, both physical and financial participants use virtual supply (increments) and virtual demand (decrements). A participant is classified as a physical entity if the entity primarily takes physical positions (fixed demand and generation) 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 grouped as 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 six months of 2011, financial companies as a group were net recipients of congestion charges, whereas physical companies were net payers of congestion charges. In the first six months of 2011, the financial companies collected $55.8 million, a decrease of $4.2 million or 7.1 percent compared to the first six months of 2010. In the first six months of 2011, the physical companies paid $616.7 million toward congestion charges, a decrease of 87.9 million or 12.5 percent compared to the first six months of 2010.

Key Backbone Facilities

PJM baseline projects are implemented to resolve reliability criteria violations. PJM backbone 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; Carson – Suffolk; Jacks Mountain; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); Susquehanna – Roseland; and the Trans Allegheny Line (TrAIL). The total planned costs for all of these projects are $6,048.4 million.

On February 28, 2011, PJM issued a press release stating that preliminary analysis of the 2011 RTEP revealed the expected reliability violations that necessitated PATH have moved several years into the future. As a result, the Board decided to hold the PATH project in abeyance in its 2011 RTEP. The Board noted that this decision was not a directive by PJM to cancel or abandon the PATH project. PJM will perform more rigorous analysis to determine the need for PATH as part of the RTEP process.[4] As a result, American Electric Power and FirstEnergy Corp. withdrew their applications for state regulatory approval of the PATH project.[5]

On May 19, 2011, the final section of the TrAIL project (the 502 Junction to Mt. Storm 500kV line) was energized. With the TrAIL line in service, the AP South interface definition was updated to include the Mt. Storm to Meadow Brook 500kV line section. Prior to the final section of the TrAIL project being energized, the AP South interface definition included the Mt. Storm to Doubs 500kV line, the Greenland Gap to Meadow Brook 500kV line and the Mt. Storm to Valley 500kV lines. The interface limit increased by 543 MW as a result of the implementation of the TrAIL line (from 725 MW prior to implementation to 1,268 MW after implementation).[6]

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 have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were three percent of total PJM billings in the first half of 2011. Total congestion costs decreased by $83.7 million or 13 percent, from $644.6 million in the first six months of 2010 to $560.9 million in the first six months of 2011. Day-ahead congestion costs decreased by $40.5 million or 5.5 percent, from $733.9 million in the first six months of 2010 to $693.5 million in the first six months of 2011. Balancing congestion costs decreased by $43.2 million or 48.3 percent, from -$89.4 million in the first six months of 2010 to -$132.6 million in the first six month of 2011. Congestion costs were significantly

4 See "Statement of Terry Boston, President and CEO, on behalf of the PJM Board of Managers". <http://www.pjm.com/~/media/documents/reports/20110228-bom-statement-planning-for-transmission.ashx>
5 See "PATH Seeks to Withdraw Applications for Electric Transmission Project". <http://www.pathtransmission.com>
6 See "TrAIL Project Impacts to the APSouth IROL" (January 11, 2011) (Accessed August 3, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110111/20110111-item-13-trail-apsouth-interface-changes.ashx> (233KB).

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 from 45,432 congestion event hours in the first six months of 2010 to 57,925 congestion event hours or 27.5 percent in the first six months of 2011. Real-time congestion frequency increased from 9,236 congestion event hours in the first six months of 2010 to 9,510 congestion event hours or 3.0 percent in the first six months of 2011.

ARRs and FTRs served as an effective, but not complete, hedge against congestion. ARR and FTR revenues hedged 96.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2009 to 2010 planning period. For the full 2010 to 2011 planning period, total ARR and FTR revenues hedged 96.9 percent of the congestion costs within PJM.[7] FTRs were paid at 84.9 percent of the target allocation level for the full 2010 to 2011 planning period, and at 86.9 percent of the target allocation level for the first six months of the 2011 to 2012 planning period.[8]

The AP South Interface was the largest contributor to congestion costs in the first six months of 2011, accounting for 31 percent of total congestion costs in the first six months of 2010. The top five constraints accounted for 57 percent of total congestion costs.

Congestion

Total Calendar Year Congestion

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 through June 2011 (See 2010 SOM, Table 7-1)

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
2009	$719	(66%)	$26,550	3%
2010	$1,428	99%	$34,770	4%
2011 (Jan - Jun)	$560		$18,705	3%
Total	$11,579		$204,062	6%

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through June, 2010 and 2011 (See 2010 SOM, Table 7-2)

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2010 (Jan - Jun)	$148.8	($521.2)	($25.5)	$644.6
2011 (Jan - Jun)	$278.7	($363.3)	($81.2)	$560.9

7 See the *2011 Quarterly State of the Market Report for PJM: January through June* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-30, "ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011."

8 See the *2011 Quarterly State of the Market Report for PJM: January through June*, 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 June 30, 2011"

Monthly Congestion

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): Calendar year 2010 through June 2011 (See 2010 SOM, Table 7-3)

	2010	2011	Change	Percent Change
Jan	$218.5	$241.8	$23.3	10.7%
Feb	$106.4	$74.0	($32.4)	(30.4%)
Mar	$20.4	$45.0	$24.6	120.8%
Apr	$42.6	$39.0	($3.6)	(8.5%)
May	$68.5	$35.5	($33.0)	(48.2%)
Jun	$188.5	$125.0	($63.5)	(33.7%)
Jul	$268.9			
Aug	$105.1			
Sep	$119.9			
Oct	$50.3			
Nov	$52.0			
Dec	$187.1			
Total	$1,428.1	$560.3		

Congestion Component of LMP

Table 7-4 Annual average congestion component of LMP: January through June 2010 and 2011 (See 2010 SOM, Table 7-4)

	2010 (Jan - Jun)		2011 (Jan - Jun)	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$2.18	$2.24	$3.76	$3.70
AEP	($3.60)	($3.81)	($3.26)	($3.76)
AP	($0.46)	($0.37)	$0.04	($0.18)
ATSI	$0.00	$0.00	($3.93)	($5.05)
BGE	$4.87	$4.72	$4.20	$4.62
ComEd	($6.00)	($6.74)	($6.99)	($7.78)
DAY	($4.33)	($4.52)	($4.08)	($4.18)
DLCO	($3.36)	($3.88)	($4.53)	($4.41)
DPL	$2.28	$2.52	$3.25	$2.99
Dominion	$6.21	$5.35	$3.93	$4.01
JCPL	$1.57	$1.79	$3.37	$3.62
Met-Ed	$2.34	$2.04	$2.97	$2.90
PECO	$1.93	$1.92	$3.34	$3.07
PENELEC	($1.55)	($2.13)	($0.54)	($0.74)
PPL	$1.52	$1.36	$3.53	$3.52
PSEG	$2.37	$2.96	$4.19	$4.43
Pepco	$6.83	$5.57	$5.86	$4.66
RECO	$1.52	$1.25	$1.07	($1.79)

Congested Facilities

Congestion by Facility Type and Voltage

Table 7-5 Congestion summary (By facility type): January through June 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	($0.5)	($52.8)	$6.2	$58.5	$5.8	$7.3	($42.8)	($44.3)	$14.2	9,629	2,676
Interface	$86.5	($233.5)	($6.2)	$313.9	$16.7	$17.8	$4.2	$3.0	$316.9	4,727	1,095
Line	$77.4	($94.0)	$12.2	$183.7	$7.9	$22.7	($40.0)	($54.7)	$128.9	30,528	3,802
Other	$0.5	($0.4)	$0.6	$1.5	$0.9	$1.2	$0.1	($0.1)	$1.3	449	71
Transformer	$82.8	($37.7)	$9.0	$129.5	($1.5)	$7.3	($26.8)	($35.6)	$93.9	12,592	1,866
Unclassified	$1.5	($1.2)	$3.8	$6.5	$0.7	($0.0)	($1.6)	($0.9)	$5.6	NA	NA
Total	$248.2	($419.6)	$25.6	$693.5	$30.5	$56.3	($106.8)	($132.6)	$560.9	57,925	9,510

Table 7-6 Congestion summary (By facility type): January through June 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	$1.9	($19.6)	$5.1	$26.6	($1.4)	$3.2	($16.2)	($20.8)	$5.8	3,471	1,033
Interface	$44.1	($348.9)	$4.0	$397.0	$9.2	$5.5	($2.3)	$1.4	$398.4	5,141	1,546
Line	$59.0	($143.2)	$23.8	$226.0	($13.9)	$7.8	($39.0)	($60.7)	$165.3	30,816	5,406
Transformer	$48.2	($28.1)	$3.5	$79.8	($0.0)	$3.0	($6.2)	($9.3)	$70.5	6,004	1,251
Unclassified	$1.8	($1.0)	$1.8	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	NA	NA
Total	$155.0	($540.7)	$38.1	$733.9	($6.2)	$19.5	($63.6)	($89.4)	$644.6	45,432	9,236

Table 7-7 Congestion Event Hours (Day Ahead against Real Time): January through June 2010 and 2011 (See 2010 SOM, Table 7-7)

	Congestion Event Hours					
	2011 (Jan - Jun)			2010 (Jan - Jun)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	9,629	1,195	12.4%	3,471	330	9.5%
Interface	4,727	774	16.4%	5,141	1,035	20.1%
Line	30,528	968	3.2%	30,816	2,082	6.8%
Other	449	0	0.0%	0	0	0.0%
Transformer	12,592	914	7.3%	6,004	487	8.1%
Total	57,925	3,851	6.6%	45,432	3,934	8.7%

Table 7-8 Congestion Event Hours (Real Time against Day Ahead): January through June 2010 and 2011 (See 2010 SOM, Table 7-8)

	Congestion Event Hours					
	2011 (Jan - Jun)			2010 (Jan - Jun)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	2,676	1,201	44.9%	1,033	348	33.7%
Interface	1,095	773	70.6%	1,546	1,035	66.9%
Line	3,802	941	24.8%	5,406	2,004	37.1%
Other	71	0	0.0%	0	0	0.0%
Transformer	1,866	903	48.4%	1,251	422	33.7%
Total	9,510	3,818	40.1%	9,236	3,809	41.2%

Table 7-9 Congestion summary (By facility voltage): January through June 2011 (See 2010 SOM, Table 7-9)

	Congestion Costs (Millions)									Event Hours	
	Day Ahead				Balancing						
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.0	($0.9)	$0.3	$1.3	$1.7	$1.0	($2.2)	($1.6)	($0.3)	15	20
500	$91.8	($239.7)	($4.9)	$326.6	$16.8	$24.0	($4.6)	($11.9)	$314.7	5,734	1,632
345	$48.2	($35.4)	$8.6	$92.3	$9.0	$15.9	($43.8)	($50.8)	$41.5	12,487	2,161
230	$38.3	($51.9)	$6.2	$96.4	$4.9	$6.9	($21.0)	($23.0)	$73.5	9,771	1,359
161	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.3)	($0.3)	($0.3)	0	21
138	$57.5	($81.9)	$9.6	$148.9	($1.8)	$5.9	($32.7)	($40.4)	$108.5	21,945	3,817
115	$3.2	($6.0)	$2.0	$11.2	($0.6)	$0.6	($0.5)	($1.7)	$9.6	3,689	257
69	$7.8	($2.1)	($0.1)	$9.8	($1.0)	$0.8	($0.3)	($2.1)	$7.8	4,234	182
34	$0.0	($0.0)	$0.0	$0.0	$0.8	$1.0	$0.1	($0.0)	($0.0)	0	61
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	43	0
Unclassified	$1.5	($1.6)	$3.8	$6.9	$0.7	($0.0)	($1.6)	($0.9)	$6.1	NA	NA
Total	$248.2	($419.6)	$25.6	$693.5	$30.5	$56.3	($106.8)	($132.6)	$560.9	57,925	9,510

Table 7-10 Congestion summary (By facility voltage): January through June 2010 (See 2010 SOM, Table 7-10)

	Congestion Costs (Millions)									Event Hours	
	Day Ahead				Balancing						
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.5	($1.8)	$0.5	$2.8	($1.1)	($0.1)	($3.2)	($4.2)	($1.4)	77	74
500	$53.0	($362.1)	$6.6	$421.7	$7.3	($1.1)	($11.0)	($2.6)	$419.1	6,247	2,305
345	$7.9	($42.6)	$8.7	$59.3	($4.9)	$5.9	($28.1)	($38.9)	$20.4	4,828	1,576
230	$34.5	($56.0)	$11.9	$102.4	($3.1)	$11.8	($13.4)	($28.4)	$74.0	10,075	1,686
138	$32.9	($78.2)	$8.3	$119.4	($2.4)	$2.0	($7.5)	($11.9)	$107.5	18,009	2,796
115	$21.3	$0.6	$0.2	$21.0	$0.3	$0.5	($0.4)	($0.6)	$20.4	2,445	665
69	$3.0	$0.3	$0.0	$2.8	($2.2)	$0.4	($0.1)	($2.7)	$0.1	3,342	134
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	37	0
14	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	21	0
12	$0.1	$0.1	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	351	0
Unclassified	$1.8	($1.0)	$1.8	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	NA	NA
Total	$155.0	($540.7)	$38.1	$733.9	($6.2)	$19.5	($63.6)	($89.4)	$644.6	45,432	9,236

Constraint Duration

Table 7-11 Top 25 constraints with frequent occurrence: January through June 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	2,943	2,943	2	419	417	0%	34%	34%	0%	5%	5%
2	Belmont	Transformer	344	2,538	2,194	9	251	242	4%	29%	25%	0%	3%	3%
3	Crete - St Johns Tap	Flowgate	330	2,095	1,765	82	605	523	4%	24%	20%	1%	7%	6%
4	AP South	Interface	2,090	2,045	(45)	1,010	629	(381)	24%	23%	(1%)	12%	7%	(4%)
5	Wylie Ridge	Transformer	51	1,842	1,791	53	354	301	1%	21%	20%	1%	4%	3%
6	Cox's Corner - Marlton	Line	1	1,637	1,636	0	0	0	0%	19%	19%	0%	0%	0%
7	Wolfcreek	Transformer	28	1,257	1,229	0	128	128	0%	14%	14%	0%	1%	1%
8	Fairview	Transformer	0	1,311	1,311	0	0	0	0%	15%	15%	0%	0%	0%
9	Oak Grove - Galesburg	Flowgate	61	891	830	72	397	325	1%	10%	9%	1%	5%	4%
10	Danville - East Danville	Line	0	1,258	1,258	0	0	0	0%	14%	14%	0%	0%	0%
11	Bunsonville - Eugene	Flowgate	31	1,164	1,133	0	0	0	0%	13%	13%	0%	0%	0%
12	Brues - West Bellaire	Line	0	846	846	4	283	279	0%	10%	10%	0%	3%	3%
13	Michigan City - Laporte	Flowgate	0	852	852	0	276	276	0%	10%	10%	0%	3%	3%
14	Linden - VFT	Line	2	1,128	1,126	0	0	0	0%	13%	13%	0%	0%	0%
15	Electric Jct - Nelson	Line	393	1,009	616	76	56	(20)	4%	12%	7%	1%	1%	(0%)
16	AEP-DOM	Interface	471	905	434	84	98	14	5%	10%	5%	1%	1%	0%
17	Emilie - Falls	Line	2	978	976	0	0	0	0%	11%	11%	0%	0%	0%
18	Cumberland - Bush	Flowgate	0	835	835	15	140	125	0%	10%	10%	0%	2%	1%
19	Pinehill - Stratford	Line	794	959	165	0	0	0	9%	11%	2%	0%	0%	0%
20	Carnegie - Tidd	Line	0	852	852	0	0	0	0%	10%	10%	0%	0%	0%
21	5004/5005 Interface	Interface	1,050	523	(527)	367	293	(74)	12%	6%	(6%)	4%	3%	(1%)
22	Clover	Transformer	57	543	486	53	246	193	1%	6%	6%	1%	3%	2%
23	Cedar Grove - Roseland	Line	89	759	670	0	26	26	1%	9%	8%	0%	0%	0%
24	Cloverdale - Lexington	Line	578	448	(130)	343	325	(18)	7%	5%	(1%)	4%	4%	(0%)
25	Pleasant Prairie - Zion	Flowgate	945	606	(339)	174	144	(30)	11%	7%	(4%)	2%	2%	(0%)

Table 7-12 Top 25 constraints with largest year-to-year change in occurrence: January through June 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	2,943	2,943	2	419	417	0%	34%	34%	0%	5%	5%
2	Athenia - Saddlebrook	Line	2,591	458	(2,133)	321	2	(319)	30%	5%	(24%)	4%	0%	(4%)
3	Belmont	Transformer	344	2,538	2,194	9	251	242	4%	29%	25%	0%	3%	3%
4	Crete - St Johns Tap	Flowgate	330	2,095	1,765	82	605	523	4%	24%	20%	1%	7%	6%
5	Wylie Ridge	Transformer	51	1,842	1,791	53	354	301	1%	21%	20%	1%	4%	3%
6	Waterman - West Dekalb	Line	1,496	0	(1,496)	223	0	(223)	17%	0%	(17%)	3%	0%	(3%)
7	Cox's Corner - Marlton	Line	1	1,637	1,636	0	0	0	0%	19%	19%	0%	0%	0%
8	East Frankfort - Crete	Line	1,650	731	(919)	604	7	(597)	19%	8%	(10%)	7%	0%	(7%)
9	Wolfcreek	Transformer	28	1,257	1,229	0	128	128	0%	14%	14%	0%	1%	1%
10	Fairview	Transformer	0	1,311	1,311	0	0	0	0%	15%	15%	0%	0%	0%
11	Tiltonsville - Windsor	Line	1,564	519	(1,045)	270	52	(218)	18%	6%	(12%)	3%	1%	(2%)
12	Danville - East Danville	Line	0	1,258	1,258	0	0	0	0%	14%	14%	0%	0%	0%
13	Oak Grove - Galesburg	Flowgate	61	891	830	72	397	325	1%	10%	9%	1%	5%	4%
14	Bunsonville - Eugene	Flowgate	31	1,164	1,133	0	0	0	0%	13%	13%	0%	0%	0%
15	Michigan City - Laporte	Flowgate	0	852	852	0	276	276	0%	10%	10%	0%	3%	3%
16	Linden - VFT	Line	2	1,128	1,126	0	0	0	0%	13%	13%	0%	0%	0%
17	Brues - West Bellaire	Line	0	846	846	4	283	279	0%	10%	10%	0%	3%	3%
18	Doubs	Transformer	915	41	(874)	283	51	(232)	10%	0%	(10%)	3%	1%	(3%)
19	Pleasant Valley - Belvidere	Line	1,277	317	(960)	220	97	(123)	15%	4%	(11%)	3%	1%	(1%)
20	Emilie - Falls	Line	2	978	976	0	0	0	0%	11%	11%	0%	0%	0%
21	Cumberland - Bush	Flowgate	0	835	835	15	140	125	0%	10%	10%	0%	2%	1%
22	Carnegie - Tidd	Line	0	852	852	0	0	0	0%	10%	10%	0%	0%	0%
23	Bedington - Black Oak	Interface	1,328	624	(704)	43	1	(42)	15%	7%	(8%)	0%	0%	(0%)
24	Cedar Grove - Roseland	Line	89	759	670	0	26	26	1%	9%	8%	0%	0%	0%
25	Danville - East Danville	Line	879	0	(879)	85	284	199	10%	0%	(10%)	1%	3%	2%

Constraint Costs

Table 7-13 Top 25 constraints affecting annual PJM congestion costs (By facility): January through June 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 - Jun)
1	AP South	Interface	500	($3.6)	($175.6)	$0.4	$172.3	$9.1	$9.2	($0.1)	($0.2)	$172.0	31%
2	5004/5005 Interface	Interface	500	$50.6	($13.2)	($4.4)	$59.4	$6.7	$7.2	$4.4	$3.9	$63.3	11%
3	Belmont	Transformer	AP	$21.3	($17.9)	($2.6)	$36.5	($2.0)	($1.5)	($0.7)	($1.2)	$35.4	6%
4	AEP-DOM	Interface	500	$2.3	($25.2)	$1.5	$29.0	$0.6	$0.4	($0.1)	$0.0	$29.1	5%
5	Bedington - Black Oak	Interface	500	$5.4	($19.5)	($2.0)	$22.9	($0.0)	($0.0)	($0.0)	$0.0	$22.9	4%
6	West	Interface	500	$26.0	$2.8	($1.3)	$21.8	$0.2	$0.0	$0.1	$0.3	$22.1	4%
7	Crete - St Johns Tap	Flowgate	MISO	$1.4	($19.6)	($3.8)	$17.1	$4.4	$3.4	($2.4)	($1.5)	$15.6	3%
8	Susquehanna	Transformer	PPL	$6.1	($8.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	3%
9	Dickerson - Quince Orchard	Line	Pepco	$17.0	$1.1	($1.5)	$14.5	$2.6	$5.7	$2.5	($0.5)	$14.0	2%
10	Wylie Ridge	Transformer	AP	$36.1	$25.3	$1.7	$12.5	$2.0	$0.9	($2.5)	($1.4)	$11.1	2%
11	Waldwick	Transformer	PSEG	$0.7	($1.0)	$2.1	$3.7	($0.1)	$1.2	($12.5)	($13.8)	($10.0)	(2%)
12	Dooms	Transformer	Dominion	($0.1)	($0.6)	$0.2	$0.7	($2.4)	$2.9	($4.6)	($9.9)	($9.2)	(2%)
13	Clover	Transformer	Dominion	$1.5	($9.0)	$2.1	$12.7	$0.2	$0.9	($3.7)	($4.5)	$8.2	1%
14	Electric Jct - Nelson	Line	ComEd	($0.4)	($12.5)	$3.3	$15.3	$0.6	$2.6	($5.3)	($7.3)	$8.0	1%
15	South Mahwah - Waldwick	Line	PSEG	$7.8	($9.3)	($1.1)	$16.0	($1.1)	$5.2	($16.6)	($22.9)	($6.9)	(1%)
16	East	Interface	500	$4.5	($3.1)	($0.2)	$7.5	$0.1	$1.2	$0.1	($1.0)	$6.5	1%
17	Bunsonville - Eugene	Flowgate	MISO	($1.1)	($6.4)	$1.1	$6.4	$0.0	$0.0	$0.0	$0.0	$6.4	1%
18	Cloverdale - Lexington	Line	AEP	$3.4	($3.1)	$0.8	$7.3	$2.2	$0.9	($2.5)	($1.1)	$6.2	1%
19	Brues - West Bellaire	Line	AEP	$9.9	$0.4	$0.3	$9.8	($1.3)	$1.5	($0.9)	($3.7)	$6.1	1%
20	Oak Grove - Galesburg	Flowgate	MISO	($2.2)	($6.1)	$4.0	$7.9	($0.8)	$2.3	($10.8)	($13.8)	($6.0)	(1%)
21	Unclassified	Unclassified	Unclassified	$1.0	($1.1)	$3.8	$5.9	$0.7	($0.0)	($1.6)	($0.9)	$5.0	1%
22	Yukon	Transformer	AP	($0.4)	($4.7)	($0.2)	$4.2	$0.4	($0.1)	$0.3	$0.7	$4.9	1%
23	Danville - East Danville	Line	AEP	($2.6)	($9.2)	($2.0)	$4.7	$0.0	$0.0	$0.0	$0.0	$4.7	1%
24	East Frankfort - Crete	Line	ComEd	$0.0	($4.4)	$0.2	$4.5	$0.0	$0.0	($0.0)	$0.0	$4.5	1%
25	Cloverdale	Transformer	AEP	$1.1	($2.6)	$0.8	$4.4	$0.2	$0.2	$0.1	$0.1	$4.5	1%

Table 7-14 Top 25 constraints affecting annual PJM congestion costs (By facility): January through June 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 - Jun)
1	AP South	Interface	500	($0.8)	($232.7)	$2.4	$234.4	$6.1	$4.8	($1.7)	($0.3)	$234.1	36%
2	Bedington - Black Oak	Interface	500	$5.2	($55.4)	$1.2	$61.8	$0.1	($0.9)	($0.5)	$0.5	$62.3	10%
3	AEP-DOM	Interface	500	$9.4	($37.9)	$0.9	$48.3	$0.1	($1.3)	($0.1)	$1.3	$49.6	8%
4	5004/5005 Interface	Interface	500	$26.2	($21.7)	($0.6)	$47.4	$2.5	$2.2	($0.1)	$0.2	$47.5	7%
5	Doubs	Transformer	AP	$16.7	($10.7)	$0.9	$28.2	($0.2)	$1.2	($2.2)	($3.6)	$24.6	4%
6	East Frankfort - Crete	Line	ComEd	$4.3	($20.7)	$2.9	$27.9	($2.7)	$1.0	($5.5)	($9.2)	$18.7	3%
7	Cloverdale - Lexington	Line	AEP	$6.9	($6.2)	$1.3	$14.4	($1.8)	($1.9)	($3.4)	($3.3)	$11.1	2%
8	Crescent	Transformer	DLCO	$6.1	($3.4)	$0.4	$9.9	$0.2	($0.6)	($0.5)	$0.2	$10.1	2%
9	Tiltonsville - Windsor	Line	AP	$8.9	($0.5)	$0.2	$9.6	($1.1)	$0.3	$0.3	($1.1)	$8.5	1%
10	Pleasant Valley - Belvidere	Line	ComEd	($5.3)	($15.8)	$1.3	$11.8	($0.0)	$2.1	($2.1)	($4.2)	$7.5	1%
11	Limerick	Transformer	PECO	$1.4	($2.0)	($0.1)	$3.2	$0.8	($3.4)	($0.1)	$4.1	$7.3	1%
12	Graceton - Raphael Road	Line	BGE	($2.4)	($7.6)	$0.6	$5.8	$0.6	($0.7)	($0.1)	$1.1	$6.9	1%
13	Mount Storm - Pruntytown	Line	AP	$0.6	($3.5)	$0.1	$4.1	$0.4	($3.5)	($1.5)	$2.4	$6.5	1%
14	Pleasant View	Transformer	Dominion	($0.1)	($0.4)	$0.0	$0.3	($2.4)	$3.5	($0.3)	($6.2)	($5.9)	(1%)
15	Pleasant Prairie - Zion	Flowgate	MISO	($2.8)	($7.0)	$2.1	$6.3	($0.4)	$1.1	($10.4)	($12.0)	($5.7)	(1%)
16	Branchburg - Readington	Line	PSEG	$2.9	($4.1)	$0.3	$7.3	($0.3)	$1.6	$0.0	($1.9)	$5.4	1%
17	Rising	Flowgate	MISO	$0.3	($4.2)	$0.6	$5.1	($0.0)	($0.0)	($0.0)	($0.0)	$5.0	1%
18	Reid - Ringgold	Line	AP	($0.4)	($5.0)	$0.3	$4.9	$0.0	($0.0)	($0.0)	$0.0	$5.0	1%
19	Unclassified	Unclassified	Unclassified	$1.8	($1.0)	$1.8	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	1%
20	Nipetown - Reid	Line	AP	$1.1	($3.2)	$0.2	$4.5	($0.0)	($0.1)	($0.1)	$0.0	$4.5	1%
21	Hunterstown	Transformer	Met-Ed	$2.1	($2.1)	$0.2	$4.3	$0.1	$0.0	($0.0)	$0.0	$4.4	1%
22	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.6)	$0.9	($2.5)	($4.0)	($4.0)	(1%)
23	Ox - Francona	Line	Dominion	$2.6	($1.4)	$0.0	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1%
24	Danville - East Danville	Line	Dominion	($3.5)	($8.2)	($0.8)	$3.9	$0.1	$0.2	$0.1	$0.0	$4.0	1%
25	Seward	Transformer	PENELEC	$10.2	$6.0	($0.1)	$4.1	($0.1)	$0.1	$0.0	($0.1)	$4.0	1%

Table 7-15 Congestion cost by the type of the participant: January through June 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	$33.5	$1.9	$30.9	$62.5	($16.7)	$2.7	($98.9)	($118.3)	($55.8)
Physical	$214.7	($421.6)	($5.3)	$631.0	$47.2	$53.6	($7.9)	($14.3)	$616.7
Total	$248.2	($419.6)	$25.6	$693.5	$30.5	$56.3	($106.8)	($132.6)	$560.9

Table 7-16 Congestion cost by the type of the participant: January through June 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	$9.2	($0.2)	$31.3	$40.7	($29.5)	$10.0	($61.3)	($100.8)	($60.1)
Physical	$145.8	($540.6)	$6.9	$693.2	$23.3	$9.6	($2.4)	$11.4	$704.6
Total	$155.0	($540.7)	$38.1	$733.9	($6.2)	$19.5	($63.6)	($89.4)	$644.6

Congestion-Event Summary for MISO Flowgates

Table 7-17 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June 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
2	Crete - St Johns Tap	$1.4	($19.6)	($3.8)	$17.1	$4.4	$3.4	($2.4)	($1.5)	$15.6	2,095	605
3	Bunsonville - Eugene	($1.1)	($6.4)	$1.1	$6.4	$0.0	$0.0	$0.0	$0.0	$6.4	1,164	0
4	Oak Grove - Galesburg	($2.2)	($6.1)	$4.0	$7.9	($0.8)	$2.3	($10.8)	($13.8)	($6.0)	891	397
5	Lakeview - Pleasant Prairie	($0.0)	($0.1)	$0.2	$0.3	($0.2)	$0.0	($4.2)	($4.4)	($4.1)	24	174
6	Pleasant Prairie - Zion	($0.1)	($0.8)	$1.7	$2.5	($0.1)	($0.2)	($6.5)	($6.3)	($3.8)	606	144
7	Crete - St. Johns	($0.2)	($3.4)	$0.0	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	349	0
8	Cook - Palisades	$0.9	($2.1)	$0.2	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	338	0
9	Michigan City - Laporte	$0.7	($2.5)	$1.0	$4.2	($0.9)	($1.0)	($2.0)	($1.8)	$2.4	852	276
10	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($1.6)	($1.7)	($1.7)	0	71
11	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.4	($0.7)	($1.2)	($1.2)	0	14
12	Monticello - Schahfer	$0.2	($0.6)	$0.5	$1.3	($0.1)	$0.1	($2.3)	($2.5)	($1.2)	207	100
13	Benton Harbor - Palisades	$0.7	($0.1)	$0.2	$1.0	$1.1	$0.8	($2.4)	($2.1)	($1.2)	67	75
14	Rantoul - Rising	($0.3)	($1.3)	$0.1	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	62	0
15	Cumberland - Bush	($0.1)	($2.4)	$0.7	$2.9	$0.1	$0.1	($2.1)	($2.0)	$0.9	835	140
16	Kenosha - Lakeview	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.9)	($0.8)	($0.8)	0	61
17	Burr Oak	$0.3	($0.5)	$0.0	$0.9	$0.1	($0.0)	($0.2)	($0.0)	$0.8	124	18
18	Rantoul - Rantoul Jct	($0.0)	($0.7)	$0.0	$0.7	$0.0	($0.0)	($0.2)	($0.1)	$0.6	147	52
19	Tanners - Miami Fort	($0.0)	($0.6)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	96	0
20	State Line - Wolf Lake	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.5)	($0.5)	($0.5)	0	22
21	Rising	($0.6)	($3.2)	($0.1)	$2.6	($0.0)	$0.5	($2.5)	($3.0)	($0.5)	497	95

Table 7-18 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June 2010 (See 2010 SOM, Table 7-16)

		Congestion Costs (Millions)									Event Hours	
		Day Ahead				Balancing						
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pleasant Prairie - Zion	($2.8)	($7.0)	$2.1	$6.3	($0.4)	$1.1	($10.4)	($12.0)	($5.7)	945	174
2	Rising	$0.3	($4.2)	$0.6	$5.1	($0.0)	($0.0)	($0.0)	($0.0)	$5.0	776	36
3	Crete - St Johns Tap	$0.3	($3.9)	$0.1	$4.4	($0.1)	$0.2	($0.8)	($1.1)	$3.2	330	82
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	363	0
7	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.7)	($0.7)	0	16
8	Beaver Valley - Sammis	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.2)	($0.4)	($0.4)	0	8
9	Burr Oak	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.2	($0.4)	($0.6)	($0.4)	76	97
10	Marktown - Inland Steel	$0.6	($0.9)	$0.6	$2.1	($0.6)	$0.8	($1.2)	($2.5)	($0.4)	400	242
11	Lanesville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.3)	($0.3)	($0.3)	0	33
12	Stillwell - Dumont	$0.0	($0.2)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	42	0
13	Bunsonville - Eugene	($0.0)	($0.3)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	31	0
14	DC Cook - Palisades	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.0)	($0.2)	($0.3)	($0.3)	0	6
15	Palisades - Roosevelt	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.2)	($0.3)	($0.3)	0	30
16	Oak Grove - Galesburg	($0.1)	($0.3)	$0.1	$0.3	$0.0	$0.1	($0.4)	($0.4)	($0.2)	61	72
17	Cumberland - Bush	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.2)	($0.2)	($0.2)	0	15
18	Kenosha - Lakeview	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	49	0
19	Benton Harbor - Palisades	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.1)	($0.1)	0	8
20	Powerton Jct. - Lilly	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.1)	($0.1)	0	15

Congestion-Event Summary for the 500 kV System

Table 7-19 Regional constraints summary (By facility): January through June 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	($3.6)	($175.6)	$0.4	$172.3	$9.1	$9.2	($0.1)	($0.2)	$172.0	2,045	629
2	5004/5005 Interface	Interface	500	$50.6	($13.2)	($4.4)	$59.4	$6.7	$7.2	$4.4	$3.9	$63.3	523	293
3	AEP-DOM	Interface	500	$2.3	($25.2)	$1.5	$29.0	$0.6	$0.4	($0.1)	$0.0	$29.1	905	98
4	Bedington - Black Oak	Interface	500	$5.4	($19.5)	($2.0)	$22.9	($0.0)	($0.0)	($0.0)	$0.0	$22.9	624	1
5	West	Interface	500	$26.0	$2.8	($1.3)	$21.8	$0.2	$0.0	$0.1	$0.3	$22.1	452	14
6	East	Interface	500	$4.5	($3.1)	($0.2)	$7.5	$0.1	$1.2	$0.1	($1.0)	$6.5	127	22
7	Central	Interface	500	$1.4	$0.3	($0.1)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	51	0
8	Harrison - Pruntytown	Line	500	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
9	Dominion East	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	0	38
10	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	4
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 June 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	($0.8)	($232.7)	$2.4	$234.4	$6.1	$4.8	($1.7)	($0.3)	$234.1	2,090	1,010
2	Bedington - Black Oak	Interface	500	$5.2	($55.4)	$1.2	$61.8	$0.1	($0.9)	($0.5)	$0.5	$62.3	1,328	43
3	AEP-DOM	Interface	500	$9.4	($37.9)	$0.9	$48.3	$0.1	($1.3)	($0.1)	$1.3	$49.6	471	84
4	5004/5005 Interface	Interface	500	$26.2	($21.7)	($0.6)	$47.4	$2.5	$2.2	($0.1)	$0.2	$47.5	1,050	367
5	West	Interface	500	$2.9	($0.2)	$0.1	$3.2	$0.3	$0.7	$0.2	($0.2)	$3.0	84	41
6	East	Interface	500	$1.0	($0.8)	($0.0)	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	75	0
7	Harrison - Pruntytown	Line	500	$1.0	($0.9)	$0.3	$2.2	($0.3)	($0.4)	($0.6)	($0.5)	$1.7	79	91
8	Central	Interface	500	$0.1	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	43	1
9	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
10	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	$0.0	$0.1	$0.1	0	2

Zonal Congestion

Summary

Table 7-21 Congestion cost summary (By control zone): January through June 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	$23.5	$7.6	$0.5	$16.4	($0.4)	($0.5)	($0.8)	($0.7)	$15.7
AEP	($44.4)	($175.5)	$3.3	$134.4	($0.3)	$17.1	($10.7)	($28.1)	$106.3
ATSI	($18.5)	($9.8)	$0.1	($8.6)	($2.1)	$2.8	($0.1)	($5.0)	($13.6)
BGE	$69.9	$50.0	$3.5	$23.5	$4.6	($0.0)	($4.7)	($0.2)	$23.3
ComEd	($238.0)	($363.9)	($2.7)	$123.1	$27.2	$15.4	($14.0)	($2.3)	$120.9
DAY	($9.7)	($14.3)	$0.1	$4.7	$1.3	$3.2	($1.8)	($3.8)	$1.0
DLCO	($30.1)	($47.3)	($0.4)	$16.7	($2.7)	($0.1)	($0.1)	($2.7)	$14.0
DPL	$36.0	$9.7	$0.6	$26.9	$0.6	$2.0	($1.0)	($2.3)	$24.6
Dominion	$76.0	($125.3)	$8.4	$209.7	($2.6)	$5.7	($21.5)	($29.8)	$179.9
External	($17.1)	($25.9)	$0.9	$9.8	($0.8)	($9.4)	($19.3)	($10.7)	($0.9)
JCPL	$43.7	$17.4	$0.3	$26.6	$1.0	$0.7	($0.6)	($0.4)	$26.3
Met-Ed	$25.2	$29.7	$0.3	($4.1)	$1.2	$0.2	($0.5)	$0.5	($3.6)
PECO	$75.7	$77.6	$0.7	($1.2)	$0.3	$2.6	($0.8)	($3.1)	($4.3)
PENELEC	($13.9)	($48.2)	$0.1	$34.4	$1.3	$3.0	($1.1)	($2.9)	$31.6
PPL	$78.2	$79.7	$3.2	$1.7	$6.0	($0.4)	($1.9)	$4.4	$6.1
PSEG	$82.2	$59.6	$2.8	$25.4	($1.3)	$13.5	($23.2)	($37.9)	($12.5)
Pepco	$108.5	$59.6	$3.7	$52.6	($2.7)	($0.6)	($4.6)	($6.7)	$45.9
RECO	$1.1	($0.2)	$0.1	$1.4	$0.0	$1.0	($0.1)	($1.0)	$0.3
Total	$248.2	($419.6)	$25.6	$693.5	$30.5	$56.3	($106.8)	($132.6)	$560.9

Table 7-22 Congestion cost summary (By control zone): January through June 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	$12.1	$4.0	$0.1	$8.1	($0.9)	$0.1	($0.1)	($1.1)	$7.0
AEP	($54.8)	($150.6)	$5.7	$101.4	($8.8)	$8.0	($8.1)	($24.9)	$76.5
AP	($12.3)	($143.9)	$0.1	$131.7	$7.5	$11.6	($1.4)	($5.6)	$126.1
BGE	$77.2	$56.0	$3.2	$24.5	$6.7	($4.4)	($3.3)	$7.8	$32.2
ComEd	($174.1)	($294.2)	($0.0)	$120.0	($7.9)	$7.0	($5.8)	($20.7)	$99.3
DAY	($6.9)	($12.5)	$1.9	$7.5	$0.4	$1.1	($2.7)	($3.4)	$4.1
DLCO	($46.2)	($74.4)	($0.1)	$28.2	($4.6)	($1.4)	($0.0)	($3.3)	$24.9
DPL	$22.8	$5.9	$0.3	$17.2	$0.9	$0.2	($0.4)	$0.2	$17.5
Dominion	$127.9	($7.7)	$7.5	$143.1	($4.7)	($0.7)	($7.9)	($11.9)	$131.2
External	($54.3)	($64.0)	($1.9)	$7.8	$8.3	($6.2)	($15.3)	($0.8)	$7.0
JCPL	$18.8	$4.5	$0.2	$14.5	$1.2	($0.4)	($0.3)	$1.3	$15.8
Met-Ed	$20.0	$12.9	$0.3	$7.3	$0.1	($0.1)	($0.2)	$0.0	$7.4
PECO	$15.9	$24.2	$0.0	($8.2)	$0.2	($2.5)	($0.0)	$2.7	($5.6)
PENELEC	($42.5)	($91.5)	($0.0)	$48.9	$9.1	$1.4	$0.2	$7.9	$56.7
PPL	$32.5	$37.6	$1.4	($3.7)	$3.4	$2.1	($0.0)	$1.2	($2.5)
PSEG	$45.9	$33.9	$15.7	$27.6	($6.5)	$8.5	($13.9)	($28.9)	($1.3)
Pepco	$172.2	$119.0	$3.9	$57.1	($10.8)	($4.9)	($4.2)	($10.1)	$47.0
RECO	$1.1	$0.1	($0.0)	$1.0	$0.2	$0.0	$0.0	$0.2	$1.1
Total	$155.0	($540.7)	$38.1	$733.9	($6.2)	$19.5	($63.6)	($89.4)	$644.6

Details of Regional and Zonal Congestion

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-23 AECO Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-21)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$5.4	$2.4	$0.0	$3.0	$0.2	($0.5)	($0.0)	$0.6	$3.6	1,046	586
2	Sherman Avenue	Transformer	AECO	$2.4	($0.1)	$0.0	$2.5	($0.1)	($0.0)	($0.0)	($0.0)	$2.5	502	24
3	Wylie Ridge	Transformer	AP	$2.7	$1.0	$0.0	$1.7	$0.1	($0.1)	($0.0)	$0.2	$2.0	3,684	708
4	West	Interface	500	$3.0	$1.1	$0.0	$1.9	$0.0	($0.0)	($0.0)	$0.0	$1.9	904	28
5	Crete - St Johns Tap	Flowgate	MISO	$1.0	$0.3	($0.0)	$0.8	$0.1	($0.0)	$0.0	$0.1	$0.9	4,190	1,210
6	Dickerson - Quince Orchard	Line	Pepco	$1.2	$0.6	$0.0	$0.6	$0.0	($0.1)	($0.0)	$0.1	$0.7	210	118
7	East	Interface	500	$1.1	$0.5	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.6	254	44
8	Shieldalloy - Vineland	Line	AECO	$2.0	$0.3	$0.1	$1.8	($1.0)	$0.4	($0.3)	($1.7)	$0.2	626	176
9	AP South	Interface	500	$0.8	$0.4	$0.1	$0.5	$0.0	($0.1)	($0.0)	$0.0	$0.6	4,090	1,258
10	South Mahwah - Waldwick	Line	PSEG	$0.6	$0.1	$0.1	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	5,886	838
11	Bridgewater - Middlesex	Line	PSEG	$0.4	$0.1	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	754	38
12	Waldwick	Transformer	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.2)	($0.1)	($0.1)	272	186
13	Cedar Grove - Roseland	Line	PSEG	($0.3)	($0.1)	($0.0)	($0.2)	($0.0)	$0.0	$0.0	($0.0)	($0.2)	1,518	52
14	Graceton - Raphael Road	Line	BGE	($0.2)	($0.1)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	106	100
15	Cloverdale - Lexington	Line	AEP	$0.2	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.2	896	650
26	Churchtown	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	0	50
41	Carlls Corner - Sherman Ave	Line	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	($0.0)	188	40
42	Carnegie - Tidd	Line	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,704	0
50	England - Merion	Line	AECO	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0
61	Cardiff	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	24

Table 7-24 AECO Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-22)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$4.1	$1.9	$0.0	$2.2	$0.3	($0.0)	($0.0)	$0.3	$2.5	2,100	734
2	England - Middletap	Line	AECO	$3.4	$0.7	$0.0	$2.7	($0.4)	($0.4)	($0.0)	($0.0)	$2.7	586	138
3	Absecon - Lewis	Line	AECO	$0.2	$0.0	$0.0	$0.2	($1.4)	$0.1	($0.1)	($1.6)	($1.4)	162	36
4	Graceton - Raphael Road	Line	BGE	($1.1)	($0.5)	($0.0)	($0.6)	($0.0)	$0.1	$0.0	($0.1)	($0.8)	394	198
5	AP South	Interface	500	$1.0	$0.5	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.6	4,180	2,020
6	Bedington - Black Oak	Interface	500	$0.9	$0.4	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	2,656	86
7	East Frankfort - Crete	Line	ComEd	$0.6	$0.2	$0.0	$0.4	$0.1	($0.0)	($0.0)	$0.1	$0.6	3,300	1,208
8	Branchburg - Readington	Line	PSEG	($0.6)	($0.2)	($0.0)	($0.4)	($0.0)	$0.0	$0.0	($0.0)	($0.4)	1,424	316
9	Doubs	Transformer	AP	$0.4	$0.1	$0.0	$0.3	$0.2	$0.0	($0.0)	$0.2	$0.4	1,830	566
10	Cloverdale - Lexington	Line	AEP	$0.3	$0.1	$0.0	$0.2	$0.1	$0.0	($0.0)	$0.1	$0.3	1,156	686
11	Tiltonsville - Windsor	Line	AP	$0.4	$0.1	$0.0	$0.3	$0.1	$0.0	($0.0)	$0.1	$0.3	3,128	540
12	Corson - Court	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.0)	($0.3)	($0.3)	14	30
13	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	($0.0)	($0.2)	($0.0)	$0.0	($0.2)	($0.2)	62	202
14	Athenia - Saddlebrook	Line	PSEG	($0.3)	($0.1)	($0.0)	($0.2)	($0.1)	$0.0	$0.0	($0.1)	($0.3)	5,182	642
15	Brandon Shores - Riverside	Line	BGE	$0.3	$0.1	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.2	146	110
17	Monroe	Transformer	AECO	$0.1	$0.0	($0.0)	$0.1	$0.1	($0.0)	$0.0	$0.1	$0.2	32	18
47	Lewis - Motts - Cedar	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	50	0
62	Sherman Avenue	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	10
66	Shieldalloy - Vineland	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	10
101	Lindenwold - Stratford	Line	AECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	1,680	0

BGE Control Zone

Table 7-25 BGE Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-23)

				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	$21.8	$19.0	$0.8	$3.7	$1.3	($0.4)	($0.7)	$1.0	$4.7	4,090	1,258
2	Dickerson - Quince Orchard	Line	Pepco	$7.7	$4.0	$0.1	$3.8	$0.6	$0.3	($0.2)	$0.1	$3.9	210	118
3	West	Interface	500	$6.4	$3.4	$0.1	$3.2	$0.0	($0.1)	($0.0)	$0.1	$3.2	904	28
4	Wylie Ridge	Transformer	AP	$6.7	$5.0	$0.3	$2.0	$0.3	($0.1)	($0.2)	$0.2	$2.2	3,684	708
5	5004/5005 Interface	Interface	500	$5.8	$3.9	$0.2	$2.0	$0.2	($0.1)	($0.2)	$0.2	$2.2	1,046	586
6	Bedington - Black Oak	Interface	500	$4.8	$3.7	$0.1	$1.2	($0.0)	($0.0)	($0.0)	($0.0)	$1.2	1,248	2
7	Crete - St Johns Tap	Flowgate	MISO	$3.1	$2.2	$0.2	$1.0	$0.2	$0.0	($0.1)	$0.1	$1.1	4,190	1,210
8	Riverside - Riverside	Other	BGE	$0.6	($0.2)	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	866	0
9	Erdman - Monument St.	Line	BGE	$0.8	($0.0)	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	14	0
10	Riverside	Other	BGE	$0.0	$0.0	$0.0	$0.0	$0.1	$0.5	($0.3)	($0.7)	($0.7)	0	134
11	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.2	($0.1)	($0.3)	$0.1	$0.1	0	110
12	AEP-DOM	Interface	500	$2.1	$1.9	$0.1	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	1,810	196
13	Danville - East Danville	Line	AEP	$2.0	$1.6	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,516	0
14	Susquehanna	Transformer	PPL	($1.0)	($0.6)	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	240	0
15	Doubs	Transformer	AP	$0.5	$0.3	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.2	$0.4	82	102
21	Glenarm - Windy Edge	Line	BGE	$0.8	$0.5	$0.1	$0.3	$0.0	$0.0	($0.1)	($0.1)	$0.3	308	38
35	Graceton - Raphael Road	Line	BGE	$0.8	$0.6	$0.0	$0.2	$0.0	$0.0	($0.2)	($0.2)	$0.1	106	100
45	Granite - Harrisonville	Line	BGE	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0
47	Gray Manor - Riverside	Line	BGE	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	48	0
54	Five Forks - Rock Ridge	Line	BGE	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.1	12	12

Table 7-26 BGE Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-24)

				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	$28.9	$23.0	$1.3	$7.2	$2.7	($1.4)	($1.2)	$2.9	$10.1	4,180	2,020
2	Bedington - Black Oak	Interface	500	$12.7	$9.7	$0.5	$3.4	$0.3	($0.2)	($0.1)	$0.5	$3.9	2,656	86
3	Doubs	Transformer	AP	$6.1	$4.6	$0.1	$1.6	$0.8	($1.2)	($0.3)	$1.7	$3.3	1,830	566
4	Brandon Shores - Riverside	Line	BGE	$2.4	($1.1)	$0.0	$3.5	($0.5)	$0.2	($0.1)	($0.7)	$2.8	146	110
5	5004/5005 Interface	Interface	500	$4.5	$2.3	$0.3	$2.5	$0.3	($0.2)	($0.2)	$0.3	$2.7	2,100	734
6	Graceton - Raphael Road	Line	BGE	$4.9	$3.2	$0.3	$2.0	$0.2	($0.5)	($0.3)	$0.4	$2.4	394	198
7	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	($0.0)	($0.2)	$0.6	$0.1	($0.7)	($0.7)	62	202
8	Mount Storm - Pruntytown	Line	AP	$0.6	$0.5	$0.0	$0.2	$0.5	($0.3)	($0.2)	$0.7	$0.9	174	488
9	Cloverdale - Lexington	Line	AEP	$2.0	$1.9	$0.1	$0.1	$0.6	($0.3)	($0.2)	$0.7	$0.9	1,156	686
10	East Frankfort - Crete	Line	ComEd	$1.8	$1.4	$0.1	$0.4	$0.2	($0.1)	($0.0)	$0.3	$0.7	3,300	1,208
11	West	Interface	500	$0.8	$0.5	$0.0	$0.3	$0.2	($0.1)	($0.0)	$0.2	$0.5	168	82
12	AEP-DOM	Interface	500	$3.1	$2.8	$0.1	$0.3	$0.2	($0.0)	($0.0)	$0.2	$0.6	942	168
13	Fort Martin - Ronco	Line	AP	$0.3	$0.1	$0.0	$0.1	$0.2	($0.1)	($0.1)	$0.2	$0.3	62	84
14	Fullerton - Windyedge	Line	BGE	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	46	0
15	Tiltonsville - Windsor	Line	AP	$1.2	$0.9	$0.1	$0.3	$0.1	($0.1)	($0.1)	$0.1	$0.4	3,128	540
33	Glenarm - Windy Edge	Line	BGE	$0.2	$0.1	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	30	26
39	Conastone - Graceton	Line	BGE	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.0	$0.0	0	6
44	East Point - Riverside	Line	BGE	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	12	10
47	Green Street - Westport	Line	BGE	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	88	0
57	Brandon Shores - Waugh Chapel	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	2	12

DPL Control Zone

Table 7-27 DPL Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-25)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$10.2	$2.6	$0.1	$7.7	$0.2	$0.2	($0.1)	($0.1)	$7.6	1,046	586
2	Wylie Ridge	Transformer	AP	$5.1	$1.1	$0.1	$4.1	$0.1	$0.2	($0.0)	($0.1)	$4.1	3,684	708
3	West	Interface	500	$5.0	$2.0	$0.1	$3.1	$0.0	($0.0)	($0.0)	$0.0	$3.1	904	28
4	AP South	Interface	500	$2.4	$0.6	$0.1	$1.9	$0.1	$0.1	($0.1)	($0.1)	$1.8	4,090	1,258
5	Crete - St Johns Tap	Flowgate	MISO	$2.0	$0.3	$0.0	$1.7	$0.1	$0.2	($0.0)	($0.2)	$1.5	4,190	1,210
6	East	Interface	500	$2.1	$0.5	$0.0	$1.6	($0.0)	$0.1	($0.0)	($0.1)	$1.5	254	44
7	Bedington - Black Oak	Interface	500	$0.8	$0.2	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.6	1,248	2
8	Dickerson - Quince Orchard	Line	Pepco	$2.0	$1.1	$0.0	$0.9	$0.1	$0.4	($0.0)	($0.3)	$0.6	210	118
9	Plymouth Meeting - Whitpain	Line	PECO	$0.6	$0.1	$0.0	$0.5	$0.1	$0.0	($0.0)	$0.0	$0.5	186	130
10	Keeney At5n	Transformer	DPL	$0.7	$0.2	$0.0	$0.5	($0.2)	$0.5	($0.1)	($0.7)	($0.2)	150	78
11	Longwood - Wye Mills	Line	DPL	$0.5	$0.1	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	584	0
12	New Church - Piney Grove	Line	DPL	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	90	0
13	Susquehanna	Transformer	PPL	($0.5)	($0.1)	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	240	0
14	South Mahwah - Waldwick	Line	PSEG	$0.7	$0.2	$0.1	$0.6	$0.0	$0.1	($0.2)	($0.3)	$0.3	5,886	838
15	Bradford - Planebrook	Line	PECO	($0.5)	($0.2)	($0.0)	($0.3)	($0.1)	($0.0)	$0.0	($0.0)	($0.4)	240	76
30	Oak Hall	Transformer	DPL	$0.2	$0.0	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	10	0
38	Hallwood - Oak Hall	Line	DPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	142	0
40	Kenney - Mount Olive	Line	DPL	$0.2	$0.1	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	80	4
44	Bellehaven - Tasley	Line	DPL	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	690	0
65	Easton	Transformer	DPL	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	48	4

Table 7-28 DPL Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-26)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$7.8	$2.4	$0.0	$5.4	$0.3	$0.2	($0.0)	$0.1	$5.5	2,100	734
2	AP South	Interface	500	$3.1	$1.2	$0.0	$1.9	$0.1	$0.0	($0.0)	$0.1	$2.0	4,180	2,020
3	Bedington - Black Oak	Interface	500	$1.9	$0.8	$0.0	$1.2	$0.0	$0.0	($0.0)	($0.0)	$1.2	2,656	86
4	East Frankfort - Crete	Line	ComEd	$1.2	$0.2	$0.0	$1.0	$0.0	$0.0	($0.0)	$0.0	$1.0	3,300	1,208
5	Graceton - Raphael Road	Line	BGE	($2.0)	($1.0)	($0.0)	($1.0)	($0.0)	($0.1)	$0.0	$0.0	($1.0)	394	198
6	Oak Hall	Transformer	DPL	$1.0	$0.2	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	468	0
7	Doubs	Transformer	AP	$0.8	$0.2	$0.0	$0.6	$0.0	($0.0)	($0.1)	$0.0	$0.7	1,830	566
8	Cecil - Colora	Line	DPL	$0.7	$0.1	$0.1	$0.6	($0.1)	$0.1	($0.1)	($0.3)	$0.3	164	36
9	Indian River At20	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.3	($0.6)	($0.0)	$0.9	$0.9	0	16
10	Cloverdale - Lexington	Line	AEP	$0.6	$0.1	$0.0	$0.5	$0.1	$0.0	($0.1)	$0.0	$0.5	1,156	686
11	Tiltonsville - Windsor	Line	AP	$0.7	$0.2	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	3,128	540
12	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.1	$0.1	$0.0	($0.0)	62	202
13	Branchburg - Readington	Line	PSEG	($0.9)	($0.4)	($0.0)	($0.5)	($0.0)	($0.0)	$0.0	$0.0	($0.5)	1,424	316
14	Longwood - Wye Mills	Line	DPL	$0.5	$0.1	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	184	0
15	Sammis - Wylie Ridge	Line	AP	$0.5	$0.1	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	988	88
18	Middletown - Mt Pleasant	Line	DPL	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	86	0
19	New Church - Piney Grove	Line	DPL	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	232	0
21	Cecil - Glassgow	Line	DPL	$0.3	$0.1	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	68	0
22	Dupont Seaford - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	$0.0	($0.2)	($0.2)	0	16
23	Kenney - Mount Olive	Line	DPL	$0.3	$0.1	$0.0	$0.2	($0.2)	$0.1	($0.0)	($0.3)	($0.1)	34	32

JCPL Control Zone

Table 7-29 JCPL Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-27)

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$13.5	$4.8	$0.0	$8.7	$0.2	$0.1	($0.0)	$0.0	$8.8	1,046	586
2	Wylie Ridge	Transformer	AP	$5.9	$2.4	$0.0	$3.5	$0.1	$0.1	($0.0)	($0.0)	$3.5	3,684	708
3	West	Interface	500	$6.1	$3.1	$0.0	$3.0	($0.0)	($0.0)	($0.0)	($0.0)	$3.0	904	28
4	South Mahwah - Waldwick	Line	PSEG	$4.1	$1.6	$0.2	$2.7	($0.0)	($0.0)	($0.2)	($0.2)	$2.4	5,886	838
5	Cedar Grove - Roseland	Line	PSEG	($2.8)	($0.9)	($0.1)	($2.0)	$0.0	$0.0	$0.0	($0.0)	($2.0)	1,518	52
6	Bridgewater - Middlesex	Line	PSEG	$3.0	$1.1	$0.0	$1.9	($0.1)	$0.1	($0.0)	($0.2)	$1.8	754	38
7	Crete - St Johns Tap	Flowgate	MISO	$2.4	$1.0	$0.0	$1.4	$0.1	$0.1	($0.0)	($0.0)	$1.4	4,190	1,210
8	Dickerson - Quince Orchard	Line	Pepco	$2.0	$1.1	$0.0	$0.9	$0.4	$0.1	($0.0)	$0.2	$1.2	210	118
9	East	Interface	500	$2.0	$0.8	$0.0	$1.2	($0.1)	$0.0	($0.0)	($0.1)	$1.1	254	44
10	Susquehanna	Transformer	PPL	$1.1	$0.3	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	240	0
11	Redoak - Sayreville	Line	JCPL	($0.4)	($1.1)	($0.0)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	864	0
12	Atlantic - Larrabee	Line	JCPL	$0.4	($0.2)	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	112	2
13	Waldwick	Transformer	PSEG	$0.5	$0.2	$0.0	$0.3	$0.0	$0.0	($0.1)	($0.1)	$0.2	272	186
14	Montville - Roseland	Line	PSEG	($0.3)	($0.0)	($0.0)	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	88	0
15	Roseland - West Caldwell	Line	PSEG	($0.4)	($0.1)	($0.0)	($0.3)	($0.0)	$0.0	$0.0	($0.0)	($0.3)	142	20
29	Kilmer - Sayreville	Line	JCPL	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	184	0
101	Lakewood - Larrabee	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
111	Kittatiny - Newton	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	14	0
286	Franklin - West Wharton	Line	JCPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	12	0
287	Larrabee - Smithburg	Line	JCPL	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	12	0

Table 7-30 JCPL Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-28)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$9.8	$3.7	$0.0	$6.1	$0.3	($0.3)	($0.1)	$0.6	$6.6	2,100	734
2	Branchburg - Readington	Line	PSEG	$2.7	($0.4)	$0.1	$3.1	($0.4)	$0.0	$0.1	($0.3)	$2.8	1,424	316
3	Athenia - Saddlebrook	Line	PSEG	($3.1)	($1.0)	($0.0)	($2.1)	($0.2)	$0.0	$0.0	($0.2)	($2.3)	5,182	642
4	Redoak - Sayreville	Line	JCPL	($0.8)	($2.3)	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	886	26
5	Graceton - Raphael Road	Line	BGE	($2.3)	($1.2)	($0.0)	($1.1)	$0.2	$0.1	$0.0	$0.1	($0.9)	394	198
6	East Frankfort - Crete	Line	ComEd	$1.5	$0.6	($0.0)	$0.9	$0.0	($0.0)	$0.0	$0.1	$0.9	3,300	1,208
7	Tiltonsville - Windsor	Line	AP	$1.0	$0.5	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	3,128	540
8	Bedington - Black Oak	Interface	500	$1.0	$0.5	$0.0	$0.5	($0.0)	($0.0)	$0.0	($0.0)	$0.5	2,656	86
9	West	Interface	500	$0.7	$0.3	$0.0	$0.4	$0.0	($0.1)	($0.0)	$0.1	$0.5	168	82
10	Doubs	Transformer	AP	$0.9	$0.6	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.2	$0.5	1,830	566
11	Cloverdale - Lexington	Line	AEP	$0.6	$0.2	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.1	$0.5	1,156	686
12	Atlantic - Larrabee	Line	JCPL	$0.3	($0.1)	$0.0	$0.4	$0.0	($0.1)	($0.0)	$0.1	$0.4	192	24
13	Sammis - Wylie Ridge	Line	AP	$0.6	$0.2	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	988	88
14	Brandon Shores - Riverside	Line	BGE	$0.5	$0.3	$0.0	$0.3	$0.1	($0.0)	($0.0)	$0.0	$0.3	146	110
15	East	Interface	500	$0.6	$0.3	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	150	0
16	Sayreville - Werner	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.3	$0.3	0	8
17	Franklin - West Wharton	Line	JCPL	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	74	0
20	Kilmer - Sayreville	Line	JCPL	$0.5	$0.3	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	234	0
151	Greystone - West Wharton	Line	JCPL	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	8	0

Met-Ed Control Zone

Table 7-31 Met-Ed Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-29)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$3.6	$5.3	$0.0	($1.7)	$0.0	$0.0	($0.0)	($0.0)	($1.7)	904	28
2	Wylie Ridge	Transformer	AP	$4.1	$6.0	$0.1	($1.8)	$0.1	$0.0	($0.0)	$0.1	($1.7)	3,684	708
3	Middletown Jct - TMI	Line	Met-Ed	$0.4	($0.7)	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	62	0
4	Crete - St Johns Tap	Flowgate	MISO	$1.6	$2.3	($0.0)	($0.7)	$0.1	$0.0	$0.0	$0.1	($0.6)	4,190	1,210
5	Dickerson - Quince Orchard	Line	Pepco	$1.0	$1.5	$0.0	($0.5)	$0.2	$0.2	($0.0)	$0.0	($0.4)	210	118
6	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.4)	($0.4)	0	30
7	Susquehanna	Transformer	PPL	$0.3	($0.0)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	240	0
8	East	Interface	500	$0.1	($0.2)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	254	44
9	Bunsonville - Eugene	Flowgate	MISO	$0.3	$0.5	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	2,328	0
10	Juniata	Transformer	PPL	$0.2	$0.4	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	50	0
11	Cedar Grove - Roseland	Line	PSEG	($0.7)	($0.9)	($0.0)	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	1,518	52
12	Yukon	Transformer	AP	($0.4)	($0.6)	($0.0)	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	468	78
13	Danville - East Danville	Line	AEP	$0.2	$0.4	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	2,516	0
14	AP South	Interface	500	$1.6	$1.5	$0.1	$0.1	$0.1	$0.0	($0.0)	$0.0	$0.2	4,090	1,258
15	Cloverdale - Lexington	Line	AEP	$0.3	$0.4	$0.0	($0.2)	$0.1	$0.0	($0.0)	$0.0	($0.1)	896	650
22	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	44	0
26	Hunterstown	Transformer	Met-Ed	$0.1	$0.1	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	22	10
43	Jackson - North Hanover	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.1	($0.0)	($0.1)	($0.0)	14	10
48	Cly - Collins	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	14
50	Jackson - TMI	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	8

Table 7-32 Met-Ed Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-30)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Hunterstown	Transformer	Met-Ed	$2.1	($0.2)	$0.1	$2.4	$0.0	$0.0	($0.0)	($0.0)	$2.4	234	52
2	5004/5005 Interface	Interface	500	$6.6	$5.6	($0.0)	$1.0	($0.1)	($0.5)	($0.0)	$0.3	$1.3	2,100	734
3	AP South	Interface	500	$3.0	$2.1	$0.0	$0.9	($0.0)	($0.0)	($0.1)	($0.1)	$0.8	4,180	2,020
4	Middletown Jct	Transformer	Met-Ed	$0.6	($0.1)	$0.0	$0.7	($0.1)	$0.0	$0.0	($0.1)	$0.6	22	8
5	Graceton - Raphael Road	Line	BGE	($1.6)	($2.2)	($0.0)	$0.6	$0.1	$0.2	$0.1	($0.0)	$0.6	394	198
6	Doubs	Transformer	AP	$1.7	$1.5	$0.1	$0.2	($0.0)	($0.1)	($0.2)	($0.1)	$0.1	1,830	566
7	Collins - Middletown Jct	Line	Met-Ed	$0.2	($0.2)	$0.0	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	238	40
8	West	Interface	500	$0.5	$0.3	$0.0	$0.2	$0.0	($0.1)	($0.0)	$0.1	$0.3	168	82
9	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	$0.0	$0.1	$0.2	$0.1	$0.0	$0.0	62	202
10	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.1	($0.2)	$0.0	$0.3	$0.3	60	54
11	Branchburg - Readington	Line	PSEG	($0.3)	($0.6)	($0.0)	$0.2	$0.0	$0.0	$0.1	$0.1	$0.3	1,424	316
12	Athenia - Saddlebrook	Line	PSEG	($0.9)	($0.8)	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.1)	($0.2)	5,182	642
13	Bedington - Black Oak	Interface	500	$1.9	$1.8	$0.1	$0.2	$0.0	$0.0	($0.0)	$0.0	$0.2	2,656	86
14	Doubs - Pleasant View	Line	AP	($0.1)	($0.1)	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	48	40
15	Fort Martin - Ronco	Line	AP	$0.1	$0.2	$0.0	($0.0)	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	62	84
25	Cly - Collins	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	36	0
34	Yorkana A	Transformer	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	0	10
44	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	28	0
48	Germantown - Straban	Line	Met-Ed	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	22	0
59	Brunner Island - Yorkana	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	2	22

PECO Control Zone

Table 7-33 PECO Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-31)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$9.6	$13.6	$0.0	($3.9)	($0.0)	($0.0)	($0.0)	$0.0	($3.9)	904	28
2	5004/5005 Interface	Interface	500	$21.2	$23.1	$0.1	($1.7)	($0.4)	$0.7	($0.1)	($1.1)	($2.8)	1,046	586
3	Wylie Ridge	Transformer	AP	$10.0	$12.7	$0.1	($2.7)	$0.0	$0.1	($0.1)	($0.1)	($2.8)	3,684	708
4	AP South	Interface	500	$3.4	$6.2	$0.1	($2.7)	($0.1)	$0.0	($0.1)	($0.2)	($2.9)	4,090	1,258
5	Plymouth Meeting - Whitpain	Line	PECO	$2.8	$0.3	$0.1	$2.5	($0.1)	$0.0	($0.0)	($0.1)	$2.4	186	130
6	Bradford - Planebrook	Line	PECO	$1.8	($0.7)	$0.0	$2.5	$0.1	$0.2	$0.0	($0.1)	$2.4	240	76
7	Dickerson - Quince Orchard	Line	Pepco	$3.7	$5.2	$0.0	($1.4)	$0.2	$0.4	($0.0)	($0.2)	($1.6)	210	118
8	Bryn Mawr - Plymouth Meeting	Line	PECO	$2.7	$0.4	$0.0	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	206	0
9	Crete - St Johns Tap	Flowgate	MISO	$3.9	$5.1	$0.0	($1.2)	$0.1	$0.2	($0.0)	($0.1)	($1.4)	4,190	1,210
10	East	Interface	500	$3.8	$1.9	$0.0	$1.9	($0.1)	$0.1	($0.0)	($0.2)	$1.7	254	44
11	Chichester	Transformer	PECO	$1.3	($0.2)	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	118	0
12	Limerick	Transformer	PECO	$1.7	$0.3	($0.0)	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	60	0
13	Yukon	Transformer	AP	($0.9)	($1.7)	($0.0)	$0.7	$0.1	($0.1)	$0.0	$0.2	$0.9	468	78
14	Susquehanna	Transformer	PPL	($0.7)	($1.5)	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	240	0
15	Bedington - Black Oak	Interface	500	$1.2	$1.8	$0.0	($0.7)	($0.0)	($0.0)	($0.0)	$0.0	($0.7)	1,248	2
17	Eddystone - Saville	Line	PECO	$0.5	($0.2)	$0.0	$0.6	$0.0	$0.1	$0.0	($0.0)	$0.6	136	32
43	Burlington - Croydon	Line	PECO	($0.1)	($0.2)	($0.0)	$0.1	$0.0	($0.1)	($0.0)	$0.1	$0.2	1,136	6
46	Chichester - Saville	Line	PECO	$0.1	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	8	0
59	North Philadelphia - Waneeta	Line	PECO	$0.0	($0.1)	($0.0)	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	390	6
65	Morton - Rid	Line	PECO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	20	0

Table 7-34 PECO Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-32)

				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	Limerick	Transformer	PECO	$3.0	$0.6	$0.0	$2.4	$0.1	($3.8)	($0.0)	$3.8	$6.3	106	36
2	5004/5005 Interface	Interface	500	$4.5	$9.7	$0.0	($5.2)	($0.0)	$0.2	($0.0)	($0.2)	($5.5)	2,100	734
3	AP South	Interface	500	$1.2	$4.5	$0.0	($3.3)	($0.1)	$0.1	($0.0)	($0.2)	($3.5)	4,180	2,020
4	Bedington - Black Oak	Interface	500	$1.2	$2.7	$0.0	($1.5)	$0.0	$0.0	($0.0)	($0.0)	($1.6)	2,656	86
5	Graceton - Raphael Road	Line	BGE	($1.4)	($2.8)	($0.0)	$1.4	$0.2	$0.4	$0.0	($0.2)	$1.2	394	198
6	Plymouth Meeting - Whitpain	Line	PECO	$1.1	$0.2	$0.0	$0.9	($0.0)	($0.0)	$0.0	$0.0	$0.9	72	2
7	Eddystone - Island Road	Line	PECO	$0.4	($0.6)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	62	0
8	Doubs	Transformer	AP	$0.8	$1.8	$0.0	($1.0)	($0.2)	($0.2)	($0.0)	($0.0)	($1.0)	1,830	566
9	East	Interface	500	$0.9	$0.3	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	150	0
10	East Frankfort - Crete	Line	ComEd	$1.1	$1.9	($0.0)	($0.8)	($0.0)	($0.1)	($0.0)	$0.0	($0.8)	3,300	1,208
11	West	Interface	500	$0.5	$1.1	$0.0	($0.6)	($0.0)	($0.1)	$0.0	$0.1	($0.5)	168	82
12	Tiltonsville - Windsor	Line	AP	$0.5	$1.2	$0.0	($0.6)	($0.0)	($0.1)	($0.0)	$0.1	($0.5)	3,128	540
13	Reid - Ringgold	Line	AP	$0.1	$0.6	$0.0	($0.5)	($0.0)	$0.0	($0.0)	($0.0)	($0.5)	540	30
14	Sammis - Wylie Ridge	Line	AP	$0.4	$0.8	$0.0	($0.4)	($0.0)	($0.0)	$0.0	($0.0)	($0.4)	988	88
15	Athenia - Saddlebrook	Line	PSEG	($0.4)	($1.0)	($0.0)	$0.6	$0.0	$0.3	$0.0	($0.3)	$0.3	5,182	642
25	Burlington - Croydon	Line	PECO	($0.1)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	($0.0)	$0.2	1,474	26
41	Emilie	Transformer	PECO	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	14	38
61	Cromby	Transformer	PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	68	44
64	Peachbottom	Transformer	PECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	6
77	Whitpain	Transformer	PECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0

PENELEC Control Zone

Table 7-35 PENELEC Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-33)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($5.4)	($26.1)	($1.5)	$19.2	$0.9	$1.5	$1.3	$0.8	$20.0	1,046	586
2	AP South	Interface	500	($15.2)	($27.5)	($0.3)	$12.0	$1.8	$0.5	$0.6	$1.9	$13.9	4,090	1,258
3	Wylie Ridge	Transformer	AP	$3.5	$15.4	$0.8	($11.1)	($0.5)	($0.3)	($0.4)	($0.6)	($11.7)	3,684	708
4	West	Interface	500	($1.8)	($8.3)	($0.4)	$6.1	$0.0	$0.1	$0.1	$0.0	$6.2	904	28
5	Bedington - Black Oak	Interface	500	($2.6)	($4.9)	($0.1)	$2.2	$0.0	$0.0	($0.0)	($0.0)	$2.2	1,248	2
6	Crete - St Johns Tap	Flowgate	MISO	$2.8	$5.0	$0.1	($2.2)	($0.1)	$0.1	($0.1)	($0.3)	($2.4)	4,190	1,210
7	Susquehanna	Transformer	PPL	$0.6	($1.1)	($0.1)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	240	0
8	Butler - Karns City	Line	AP	$4.6	$2.9	$0.3	$2.0	($0.1)	$0.0	($0.1)	($0.3)	$1.7	738	88
9	Yukon	Transformer	AP	$0.6	($0.9)	($0.0)	$1.4	($0.1)	($0.0)	$0.0	($0.1)	$1.4	468	78
10	AEP-DOM	Interface	500	($1.2)	($1.9)	$0.0	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	1,810	196
11	East	Interface	500	($0.4)	($1.2)	($0.1)	$0.6	$0.0	$0.1	$0.1	$0.0	$0.7	254	44
12	Blairsville East	Transformer	PENELEC	($1.4)	($1.7)	($0.1)	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	368	12
13	South Mahwah - Waldwick	Line	PSEG	($3.1)	($2.7)	$0.7	$0.3	$0.4	$0.1	($1.1)	($0.8)	($0.5)	5,886	838
14	Susquehanna	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.1	($0.0)	($0.0)	0	104
15	Gore - Hampshire	Line	AP	($0.7)	($1.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	622	0
17	Keystone - Shelocta	Line	PENELEC	($0.2)	($0.1)	($0.0)	($0.1)	($0.4)	$0.0	($0.0)	($0.5)	($0.6)	24	16
19	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.1	$0.5	$0.1	($0.4)	($0.4)	160	32
31	Laurel Lake - Tiffany	Line	PENELEC	$0.3	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	80	0
35	Goudey - Laurel Lake	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.0	($0.0)	($0.3)	($0.3)	0	24
39	Erie West	Transformer	PENELEC	$0.5	($0.0)	$0.0	$0.5	($0.3)	$0.2	($0.2)	($0.7)	($0.2)	574	60

Table 7-36 PENELEC Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-34)

				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	($31.7)	($47.9)	($0.0)	$16.1	$3.8	($0.5)	$0.0	$4.4	$20.5	4,180	2,020
2	5004/5005 Interface	Interface	500	($7.1)	($22.8)	($0.1)	$15.5	$1.1	$0.3	$0.1	$0.9	$16.4	2,100	734
3	Bedington - Black Oak	Interface	500	($11.8)	($17.9)	($0.0)	$6.1	$0.2	($0.1)	$0.0	$0.4	$6.4	2,656	86
4	Seward	Transformer	PENELEC	$10.2	$6.2	$0.0	$4.0	($0.1)	$0.1	($0.0)	($0.1)	$3.9	688	86
5	AEP-DOM	Interface	500	($4.4)	($6.3)	($0.0)	$1.8	$0.2	($0.1)	$0.0	$0.3	$2.1	942	168
6	East Frankfort - Crete	Line	ComEd	$3.3	$4.2	$0.0	($0.9)	($0.4)	$0.2	($0.0)	($0.6)	($1.5)	3,300	1,208
7	Mount Storm - Pruntytown	Line	AP	($0.6)	($1.0)	($0.0)	$0.4	$1.3	$0.3	$0.0	$1.0	$1.4	174	488
8	Sammis - Wylie Ridge	Line	AP	$0.5	$1.8	$0.0	($1.3)	($0.1)	($0.1)	($0.0)	($0.0)	($1.3)	988	88
9	Doubs	Transformer	AP	($1.7)	($2.3)	$0.0	$0.6	$0.2	($0.0)	($0.0)	$0.2	$0.8	1,830	566
10	Tiltonsville - Windsor	Line	AP	$2.1	$2.8	$0.0	($0.7)	($0.3)	$0.2	($0.0)	($0.5)	($1.2)	3,128	540
11	Homer City - Seward	Line	PENELEC	$3.3	$2.3	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	118	0
12	Hunterstown	Transformer	Met-Ed	($0.6)	($1.5)	($0.0)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	234	52
13	Pleasant View	Transformer	Dominion	($0.0)	($0.1)	($0.0)	$0.0	$0.6	($0.3)	$0.0	$1.0	$1.0	62	202
14	Graceton - Raphael Road	Line	BGE	($1.5)	($2.2)	$0.0	$0.7	$0.2	$0.1	($0.0)	$0.2	$0.8	394	198
15	West	Interface	500	($0.3)	($1.1)	$0.0	$0.8	$0.2	$0.1	$0.0	$0.0	$0.8	168	82
19	Garrett	Transformer	PENELEC	$1.1	$0.9	$0.0	$0.2	$0.0	$0.1	$0.0	($0.0)	$0.2	204	6
23	Homer City - Johnstown	Line	PENELEC	$0.9	$0.6	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	64	0
25	Homer City - Shelocta	Line	PENELEC	($2.8)	($2.8)	($0.0)	$0.0	$0.1	$0.1	$0.0	$0.0	$0.1	198	44
26	Altoona - Bear Rock	Line	PENELEC	($0.5)	($0.9)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	32	0
29	Homer City	Transformer	PENELEC	$0.7	$0.4	($0.0)	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	162	2

Pepco Control Zone

Table 7-37 Pepco Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-35)

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
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	$40.3	$26.1	$1.0	$15.2	($1.5)	($1.1)	($0.9)	($1.4)	$13.9	4,090	1,258
2	Dickerson - Quince Orchard	Line	Pepco	$18.8	$5.1	$0.2	$13.9	$0.3	$1.3	($0.2)	($1.2)	$12.7	210	118
3	Wylie Ridge	Transformer	AP	$8.2	$5.1	$0.3	$3.5	($0.3)	($0.2)	($0.1)	($0.1)	$3.4	3,684	708
4	Bedington - Black Oak	Interface	500	$7.9	$5.0	$0.2	$3.1	($0.0)	($0.0)	($0.0)	($0.0)	$3.1	1,248	2
5	West	Interface	500	$5.5	$3.1	$0.2	$2.6	($0.0)	($0.0)	($0.0)	$0.0	$2.6	904	28
6	Crete - St Johns Tap	Flowgate	MISO	$4.1	$2.4	$0.1	$1.8	($0.1)	($0.0)	($0.1)	($0.2)	$1.6	4,190	1,210
7	Danville - East Danville	Line	AEP	$3.6	$2.0	($0.0)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	2,516	0
8	AEP-DOM	Interface	500	$4.1	$2.7	$0.1	$1.5	($0.0)	($0.1)	$0.0	$0.0	$1.5	1,810	196
9	5004/5005 Interface	Interface	500	$3.8	$2.3	$0.0	$1.5	($0.1)	($0.1)	($0.1)	($0.1)	$1.4	1,046	586
10	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.2	($0.3)	($0.8)	($0.8)	0	110
11	Cloverdale - Lexington	Line	AEP	$1.6	$0.9	$0.1	$0.8	($0.1)	($0.1)	($0.2)	($0.1)	$0.7	896	650
12	Chaparral - Carson	Line	Dominion	$0.8	$0.4	$0.2	$0.5	($0.1)	($0.0)	($0.7)	($0.8)	($0.2)	392	360
13	Susquehanna	Transformer	PPL	($1.4)	($0.8)	($0.0)	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	240	0
14	Gore - Hampshire	Line	AP	$1.4	$0.8	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	622	0
15	East	Interface	500	($1.3)	($0.9)	($0.0)	($0.4)	$0.0	$0.1	$0.0	($0.1)	($0.6)	254	44
18	Burches Hill	Transformer	Pepco	$0.6	$0.3	$0.1	$0.4	$0.0	($0.0)	($0.2)	($0.2)	$0.1	134	88
55	Buzzard - Ritchie	Line	Pepco	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	138	0
303	Butler - Cabot	Line	Pepco	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	22	0
368	Pumphrey - Westport	Line	Pepco	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	24	0
387	Benning	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0

Table 7-38 Pepco Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-36)

				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	$69.6	$51.6	$1.4	$19.3	($2.7)	($1.6)	($1.4)	($2.5)	$16.9	4,180	2,020
2	Bedington - Black Oak	Interface	500	$28.5	$19.8	$0.6	$9.3	($0.3)	($0.4)	($0.3)	($0.1)	$9.2	2,656	86
3	Doubs	Transformer	AP	$18.6	$12.1	$0.5	$7.1	($3.0)	$0.7	($1.5)	($5.2)	$1.9	1,830	566
4	Reid - Ringgold	Line	AP	$4.6	$2.8	$0.1	$2.0	($0.0)	($0.0)	($0.0)	($0.0)	$2.0	540	30
5	Mount Storm - Pruntytown	Line	AP	$1.5	$1.0	$0.0	$0.5	($1.1)	($1.1)	($0.2)	($0.2)	$0.2	174	488
6	Graceton - Raphael Road	Line	BGE	$5.3	$3.6	$0.2	$1.9	($0.6)	($0.4)	($0.1)	($0.3)	$1.6	394	198
7	AEP-DOM	Interface	500	$8.0	$6.6	$0.1	$1.5	($0.1)	($0.2)	($0.1)	($0.0)	$1.5	942	168
8	5004/5005 Interface	Interface	500	$4.7	$3.2	$0.2	$1.7	($0.1)	($0.1)	($0.1)	($0.2)	$1.5	2,100	734
9	Bowie	Line	Pepco	$2.3	$1.1	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	88	0
10	Cloverdale - Lexington	Line	AEP	$4.7	$3.3	$0.1	$1.5	($0.9)	($0.7)	($0.2)	($0.4)	$1.1	1,156	686
11	East Frankfort - Crete	Line	ComEd	$3.7	$2.2	$0.0	$1.5	($0.3)	($0.0)	($0.0)	($0.2)	$1.2	3,300	1,208
12	Bowie - Lanham	Line	Pepco	$2.2	$0.9	$0.1	$1.4	($0.3)	($0.2)	($0.1)	($0.2)	$1.1	72	26
13	Tiltonsville - Windsor	Line	AP	$2.4	$1.5	$0.0	$1.0	($0.2)	($0.0)	($0.1)	($0.2)	$0.8	3,128	540
14	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	$0.2	$0.5	$0.8	$0.8	62	202
15	Danville - East Danville	Line	Dominion	$3.1	$2.1	($0.1)	$0.9	($0.2)	($0.1)	$0.1	($0.1)	$0.8	1,758	170
17	Benning - Ritchie	Line	Pepco	$0.8	$0.2	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	156	0
21	Buzzard - Ritchie	Line	Pepco	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	116	2
27	Bowie	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.2	$0.4	($0.1)	($0.3)	($0.3)	0	18
32	Burtonsville - Metzerott Rd.	Line	Pepco	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	34	0
85	Dickerson - Pleasant View	Line	Pepco	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	132	28

PPL Control Zone

Table 7-39 PPL Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-37)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$28.2	$36.8	$0.8	($7.8)	$1.5	$0.1	($0.3)	$1.1	($6.7)	1,046	586
2	Susquehanna	Transformer	PPL	$12.6	$2.7	$0.2	$10.1	$0.0	$0.0	$0.0	$0.0	$10.1	240	0
3	Wylie Ridge	Transformer	AP	$10.9	$13.6	$0.4	($2.3)	$0.6	$0.1	($0.1)	$0.4	($1.9)	3,684	708
4	West	Interface	500	$9.5	$10.6	$0.4	($0.8)	$0.0	($0.1)	($0.0)	$0.1	($0.7)	904	28
5	Crete - St Johns Tap	Flowgate	MISO	$4.2	$5.4	$0.0	($1.2)	$0.3	$0.2	($0.0)	$0.1	($1.1)	4,190	1,210
6	Susquehanna	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	$0.6	($1.3)	($0.2)	$1.7	$1.7	0	104
7	AP South	Interface	500	($0.2)	($1.3)	$0.3	$1.3	$0.2	$0.1	($0.0)	$0.1	$1.4	4,090	1,258
8	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.4	($0.7)	($0.0)	$1.1	$1.1	0	30
9	Cedar Grove - Roseland	Line	PSEG	($1.9)	($2.4)	($0.2)	$0.3	($0.1)	($0.0)	$0.0	($0.1)	$0.3	1,518	52
10	East	Interface	500	($0.0)	($0.9)	$0.0	$0.9	$0.0	$0.0	$0.1	$0.1	$1.0	254	44
11	Dickerson - Quince Orchard	Line	Pepco	$2.6	$2.6	$0.1	$0.1	$0.4	$0.4	($0.0)	($0.1)	$0.0	210	118
12	Wescosville	Transformer	PPL	$1.1	$0.5	$0.0	$0.6	$0.2	$0.1	($0.0)	$0.1	$0.8	70	38
13	South Mahwah - Waldwick	Line	PSEG	$1.5	$1.9	$0.5	$0.1	$0.2	$0.2	($0.6)	($0.6)	($0.4)	5,886	838
14	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.1	$0.1	$0.3	$0.3	$0.6	$0.6	$0.6	160	32
15	Waldwick	Transformer	PSEG	$0.2	$0.2	$0.0	$0.0	$0.1	$0.2	($0.6)	($0.7)	($0.6)	272	186
20	Juniata	Transformer	PPL	$0.6	$0.5	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	50	0
28	Elroy	Transformer	PPL	$0.4	$0.5	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	382	0
49	Dauphin - Juniata	Line	PPL	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	8	0
56	Blooming Grove - Peckville	Line	PPL	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	18	0
193	Quarry - Steel City	Line	PPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	4

Table 7-40 PPL Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-38)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$21.2	$26.9	$0.6	($5.1)	$0.6	$0.4	($0.2)	($0.1)	($5.2)	2,100	734
2	Graceton - Raphael Road	Line	BGE	($3.4)	($4.5)	($0.1)	$1.0	$0.0	$0.0	$0.0	($0.0)	$1.0	394	198
3	AP South	Interface	500	$1.6	$1.1	$0.3	$0.8	$0.2	($0.1)	($0.0)	$0.2	$1.1	4,180	2,020
4	East Frankfort - Crete	Line	ComEd	$2.6	$3.5	$0.0	($0.9)	$0.2	($0.0)	$0.0	$0.2	($0.7)	3,300	1,208
5	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.1	$0.1	$0.7	$0.2	$0.4	$0.9	$1.0	60	54
6	Harwood - Susquehanna	Line	PPL	$0.2	($0.7)	$0.0	$0.9	$0.3	$0.5	($0.1)	($0.3)	$0.6	50	44
7	Susquehanna	Transformer	PPL	$1.0	$0.3	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	72	0
8	Tiltonsville - Windsor	Line	AP	$1.6	$2.1	$0.1	($0.4)	$0.1	$0.0	$0.0	$0.1	($0.4)	3,128	540
9	Sammis - Wylie Ridge	Line	AP	$1.2	$1.6	$0.0	($0.4)	($0.0)	$0.0	($0.0)	($0.0)	($0.4)	988	88
10	Cloverdale - Lexington	Line	AEP	$1.1	$1.6	$0.1	($0.5)	$0.2	$0.0	$0.0	$0.2	($0.2)	1,156	686
11	Bedington - Black Oak	Interface	500	$1.6	$1.4	$0.2	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	2,656	86
12	West	Interface	500	$1.3	$1.5	$0.0	($0.2)	$0.0	$0.1	($0.0)	($0.1)	($0.3)	168	82
13	Martins Creek - Siegfried	Line	PPL	($0.0)	($0.1)	$0.0	$0.0	($0.0)	$0.2	($0.1)	($0.3)	($0.3)	14	34
14	Mahans Lane - Tidd	Line	AEP	$0.4	$0.6	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.2)	536	240
15	Palisades - Vergennes	Flowgate	MISO	$0.5	$0.7	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	470	182
19	Otter Creek - Safe Harbor	Line	PPL	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	$0.0	($0.0)	($0.0)	0	10
29	Alburtis - Hosensack	Line	PPL	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	($0.0)	($0.1)	($0.1)	0	50
31	Juniata	Transformer	PPL	$0.5	$0.5	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	42	0
62	Facerock	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.0	$0.0	$0.0	0	12
75	Harwood	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	26	0

PSEG Control Zone

Table 7-41 PSEG Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-39)

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	South Mahwah - Waldwick	Line	PSEG	$15.3	$3.8	($5.7)	$5.8	($1.8)	$4.0	($9.6)	($15.4)	($9.6)	5,886	838
2	5004/5005 Interface	Interface	500	$17.0	$16.4	$1.0	$1.6	$0.2	$3.0	($0.8)	($3.6)	($1.9)	1,046	586
3	Waldwick	Transformer	PSEG	$1.4	$0.4	$1.4	$2.3	($0.6)	$0.6	($7.6)	($8.7)	($6.4)	272	186
4	Cedar Grove - Roseland	Line	PSEG	$6.2	$0.9	$0.1	$5.4	($0.1)	$0.6	($0.1)	($0.7)	$4.7	1,518	52
5	Wylie Ridge	Transformer	AP	$8.1	$8.3	$0.7	$0.5	$0.0	$1.0	($0.4)	($1.4)	($0.9)	3,684	708
6	West	Interface	500	$8.6	$8.0	$0.6	$1.2	($0.0)	$0.1	($0.0)	($0.2)	$1.0	904	28
7	AP South	Interface	500	($1.2)	$2.2	$1.0	($2.5)	$0.1	($0.3)	($0.9)	($0.5)	($3.0)	4,090	1,258
8	East	Interface	500	$2.8	$3.4	$0.2	($0.4)	($0.1)	$0.5	($0.1)	($0.7)	($1.1)	254	44
9	Crete - St Johns Tap	Flowgate	MISO	$3.7	$3.6	$0.0	$0.2	$0.1	$0.5	($0.1)	($0.5)	($0.3)	4,190	1,210
10	Branchburg - Readington	Line	PSEG	$1.8	$0.1	$0.1	$1.9	($0.1)	$0.3	($0.0)	($0.5)	$1.4	422	70
11	Susquehanna	Transformer	PPL	$1.2	($0.1)	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	240	0
12	Dickerson - Quince Orchard	Line	Pepco	$2.8	$3.0	$0.2	$0.0	$0.3	$0.4	($0.2)	($0.3)	($0.3)	210	118
13	Bedington - Black Oak	Interface	500	$0.3	$1.0	$0.2	($0.5)	$0.0	($0.0)	($0.0)	($0.0)	($0.5)	1,248	2
14	Roseland - West Caldwell	Line	PSEG	$1.0	$0.1	$0.1	$1.0	($0.0)	$0.2	($0.1)	($0.3)	$0.7	142	20
15	Hawthorn - Waldwick	Line	PSEG	$0.1	$0.0	$0.5	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,038	0
17	Montville - Roseland	Line	PSEG	$0.7	$0.2	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	88	0
22	Bayway - Federal Square	Line	PSEG	$0.3	($0.2)	$0.1	$0.5	($0.0)	$0.1	($0.0)	($0.1)	$0.4	716	16
28	Athenia - Saddlebrook	Line	PSEG	$0.3	$0.1	$0.1	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	916	4
38	Linden - North Ave	Line	PSEG	$0.1	($0.1)	$0.0	$0.2	($0.0)	($0.0)	$0.0	$0.0	$0.2	160	6
39	Fairlawn	Transformer	PSEG	$0.1	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	198	0

Table 7-42 PSEG Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-40)

				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	Athenia - Saddlebrook	Line	PSEG	$12.3	$2.4	$7.2	$17.1	($6.8)	$2.7	($4.9)	($14.3)	$2.7	5,182	642
2	5004/5005 Interface	Interface	500	$13.7	$14.1	$1.4	$1.0	($0.0)	$1.0	($0.7)	($1.7)	($0.7)	2,100	734
3	Branchburg - Readington	Line	PSEG	$5.1	$0.8	$0.4	$4.7	$0.1	$0.8	($0.5)	($1.2)	$3.5	1,424	316
4	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.7)	$1.1	($1.7)	($3.4)	($3.4)	908	76
5	AP South	Interface	500	$0.4	$3.5	$1.7	($1.5)	$0.1	($0.3)	($1.2)	($0.8)	($2.3)	4,180	2,020
6	Bedington - Black Oak	Interface	500	$1.2	$2.6	$0.7	($0.7)	($0.0)	($0.0)	($0.1)	($0.1)	($0.8)	2,656	86
7	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.1)	$0.4	($0.9)	($1.4)	($1.6)	418	70
8	Graceton - Raphael Road	Line	BGE	($3.2)	($3.4)	($0.2)	($0.0)	$0.3	($0.2)	$0.3	$0.8	$0.8	394	198
9	East Frankfort - Crete	Line	ComEd	$2.3	$2.4	$0.1	$0.0	($0.1)	$0.2	($0.1)	($0.4)	($0.4)	3,300	1,208
10	Doubs	Transformer	AP	$1.3	$1.1	$0.2	$0.4	($0.3)	$0.3	($0.5)	($1.1)	($0.7)	1,830	566
11	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	($0.2)	$0.2	$0.7	$0.7	62	202
12	Fairlawn - Saddlebrook	Line	PSEG	$0.4	$0.3	$0.7	$0.8	($0.0)	$0.1	($0.4)	($0.5)	$0.3	940	34
13	Cloverdale - Lexington	Line	AEP	$1.0	$1.3	$0.1	($0.2)	$0.1	$0.3	($0.2)	($0.4)	($0.5)	1,156	686
14	Bayway - Federal Square	Line	PSEG	$0.4	($0.2)	$0.0	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.6	688	2
15	Redoak - Sayreville	Line	JCPL	$0.4	($0.1)	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.0)	$0.6	886	26
16	Bayonne - PVSC	Line	PSEG	$0.0	($0.5)	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	1,156	0
21	Hudson - Marion	Line	PSEG	$0.3	$0.1	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	340	0
22	Leonia - New Milford	Line	PSEG	$0.2	$0.1	$0.4	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	1,136	2
24	North Ave - Pvsc	Line	PSEG	$0.1	($0.3)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	570	0
29	Cedar Grove - Clifton	Line	PSEG	$0.2	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	126	0

RECO Control Zone

Table 7-43 RECO Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-41)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	South Mahwah - Waldwick	Line	PSEG	($1.2)	($0.6)	($0.0)	($0.7)	($0.0)	$1.0	$0.0	($1.0)	($1.6)	5,886	838
2	5004/5005 Interface	Interface	500	$0.7	$0.1	$0.0	$0.6	$0.0	($0.1)	($0.0)	$0.1	$0.6	1,046	586
3	Waldwick	Transformer	PSEG	($0.2)	($0.1)	($0.0)	($0.1)	($0.1)	$0.4	$0.0	($0.4)	($0.5)	272	186
4	West	Interface	500	$0.3	$0.0	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	904	28
5	Wylie Ridge	Transformer	AP	$0.3	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	3,684	708
6	Cedar Grove - Roseland	Line	PSEG	$0.3	$0.1	$0.0	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	1,518	52
7	Crete - St Johns Tap	Flowgate	MISO	$0.2	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	4,190	1,210
8	Dickerson - Quince Orchard	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	210	118
9	AP South	Interface	500	($0.1)	($0.0)	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.1)	4,090	1,258
10	Branchburg - Readington	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	422	70
11	East	Interface	500	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	254	44
12	Susquehanna	Transformer	PPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	240	0
13	Roseland - West Caldwell	Line	PSEG	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	142	20
14	Athenia - Saddlebrook	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	916	4
15	Bunsonville - Eugene	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2,328	0

Table 7-44 RECO Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-42)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$0.5	$0.1	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.1	$0.5	2,100	734
2	Branchburg - Readington	Line	PSEG	$0.3	$0.0	$0.0	$0.3	$0.1	($0.0)	($0.0)	$0.1	$0.4	1,424	316
3	Athenia - Saddlebrook	Line	PSEG	$0.2	$0.0	($0.0)	$0.1	$0.0	($0.1)	$0.0	$0.1	$0.2	5,182	642
4	AP South	Interface	500	($0.1)	($0.0)	$0.0	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	($0.2)	4,180	2,020
5	Graceton - Raphael Road	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	394	198
6	Hawthorn - Hinchmans Ave	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	418	70
7	Hawthorn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	908	76
8	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	3,300	1,208
9	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	1,830	566
10	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	3,128	540
11	West	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	168	82
12	Brandon Shores - Riverside	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	146	110
13	Fairlawn - Saddlebrook	Line	PSEG	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	940	34
14	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	62	202
15	Cloverdale - Lexington	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	1,156	686

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-45 AEP Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-43)

				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	($17.5)	($44.4)	($0.9)	$25.9	($0.0)	$3.4	$1.5	($1.9)	$24.0	4,090	1,258
2	Belmont	Transformer	AP	$10.8	($8.4)	$2.5	$21.7	($1.1)	($0.2)	($2.0)	($2.9)	$18.8	5,076	502
3	AEP-DOM	Interface	500	$3.2	($14.8)	$1.7	$19.8	($0.1)	$0.5	($0.2)	($0.8)	$19.0	1,810	196
4	5004/5005 Interface	Interface	500	($14.4)	($23.3)	($0.6)	$8.2	$0.4	$1.4	$0.7	($0.3)	$7.9	1,046	586
5	Brues - West Bellaire	Line	AEP	$10.4	$0.8	$1.2	$10.8	($1.1)	$1.6	($1.4)	($4.1)	$6.7	1,692	566
6	Wylie Ridge	Transformer	AP	($10.4)	($16.5)	($1.3)	$4.7	$0.2	$0.9	$0.6	($0.1)	$4.6	3,684	708
7	West	Interface	500	($6.1)	($10.0)	($0.3)	$3.6	$0.0	$0.1	$0.0	($0.0)	$3.6	904	28
8	Bedington - Black Oak	Interface	500	($3.4)	($7.6)	($0.1)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	1,248	2
9	Danville - East Danville	Line	AEP	($9.4)	($9.8)	($3.3)	($2.9)	$0.0	$0.0	$0.0	$0.0	($2.9)	2,516	0
10	Muskingum River	Transformer	AEP	$0.6	($2.7)	$0.5	$3.8	$0.0	$0.0	$0.0	$0.0	$3.8	586	0
11	Michigan City - Laporte	Flowgate	MISO	$4.6	$2.1	$1.6	$4.2	($1.6)	($0.9)	($1.9)	($2.7)	$1.5	1,704	552
12	Wolfcreek	Transformer	AEP	($0.4)	($3.5)	$0.6	$3.7	($0.2)	$0.1	($0.5)	($0.7)	$3.0	2,514	256
13	Carnegie - Tidd	Line	AECO	($0.8)	($3.0)	($0.6)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	1,704	0
14	Kammer	Transformer	AEP	$0.0	$0.0	$0.0	$0.0	($2.1)	($0.0)	($0.4)	($2.5)	($2.5)	0	20
15	Cumberland - Bush	Flowgate	MISO	$0.1	($2.0)	($0.1)	$2.0	$0.0	$0.1	($0.0)	($0.1)	$1.9	1,670	280
18	Ruth - Turner	Line	AEP	$1.0	($0.3)	$0.2	$1.5	($0.1)	$0.1	($0.1)	($0.3)	$1.3	150	88
22	Cloverdale	Transformer	AEP	($0.2)	($2.1)	$0.2	$2.1	($0.1)	$0.5	$0.0	($0.5)	$1.5	518	174
23	Baker - Broadford	Line	AEP	$0.2	($0.4)	$0.1	$0.8	$0.0	$1.2	($1.1)	($2.3)	($1.5)	16	40
25	Dumont - Stillwell	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($1.2)	($1.3)	($1.2)	108	54
29	Carnegie - Tidd	Line	AEP	($0.4)	($1.1)	($0.3)	$0.4	$0.2	$0.2	$0.6	$0.6	$1.0	646	666

Table 7-46 AEP Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-44)

				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	($20.3)	($52.9)	$0.4	$33.0	($3.4)	$1.7	$0.6	($4.5)	$28.5	4,180	2,020
2	AEP-DOM	Interface	500	$7.5	($20.1)	$1.0	$28.5	($0.2)	($0.3)	($0.3)	($0.1)	$28.4	942	168
3	Bedington - Black Oak	Interface	500	($8.7)	($18.6)	$0.1	$10.0	($0.1)	($0.0)	$0.0	($0.1)	$9.9	2,656	86
4	Baker - Broadford	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($1.5)	$1.0	($3.5)	($5.9)	($5.6)	20	148
5	5004/5005 Interface	Interface	500	($10.3)	($15.7)	($0.2)	$5.2	($0.8)	$1.2	$0.2	($1.7)	$3.4	2,100	734
6	Kanawha River	Transformer	AEP	$2.1	($0.2)	$0.4	$2.7	$0.0	($0.0)	($0.0)	$0.0	$2.7	324	22
7	Kanawha - Kincaid	Line	AEP	$1.4	($0.7)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	440	0
8	Culloden - Wyoming	Line	AEP	$0.6	($0.8)	$0.5	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	92	0
9	Sullivan	Transformer	AEP	($0.0)	($1.4)	($0.0)	$1.3	$0.0	$0.0	$0.0	($0.0)	$1.3	370	94
10	Doubs	Transformer	AP	($5.5)	($6.4)	($0.1)	$0.8	($0.1)	$0.3	$0.1	($0.3)	$0.5	1,830	566
11	Mahans Lane - Tidd	Line	AEP	($0.4)	($1.6)	($0.1)	$1.2	$0.1	$0.0	$0.0	$0.1	$1.3	536	240
12	Palisades - Vergennes	Flowgate	MISO	($0.3)	($1.3)	($0.2)	$0.8	$0.0	$0.1	$0.0	($0.1)	$0.8	470	182
13	Belmont	Transformer	AP	$0.9	($0.1)	$0.1	$1.0	$0.2	($0.0)	($0.0)	$0.3	$1.3	688	18
14	Cloverdale - Lexington	Line	AEP	($4.8)	($4.6)	($0.3)	($0.5)	($0.4)	$0.7	$0.4	($0.7)	($1.2)	1,156	686
15	East Frankfort - Crete	Line	ComEd	$4.6	$4.1	$1.3	$1.8	$0.2	($0.1)	($1.0)	($0.7)	$1.1	3,300	1,208
18	Kammer - Natrium	Line	AEP	$0.3	($0.4)	$0.0	$0.7	$0.0	($0.0)	($0.0)	$0.1	$0.8	356	38
25	Ruth - Turner	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	44	22
29	Conesville Prep - Conesville	Line	AEP	($0.0)	($0.4)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	236	0
31	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.1)	($0.0)	($0.3)	($0.3)	0	96
33	Breed - Wheatland	Line	AEP	$0.0	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	52	0

AP Control Zone

Table 7-47 AP Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-45)

				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	($15.3)	($62.4)	($6.5)	$40.6	$3.0	$3.6	$5.6	$5.0	$45.7	4,090	1,258
2	Belmont	Transformer	AP	$19.4	$1.3	$1.0	$19.0	($1.2)	($1.3)	($0.6)	($0.6)	$18.5	5,076	502
3	Bedington - Black Oak	Interface	500	($2.2)	($10.5)	($1.9)	$6.3	$0.0	($0.0)	$0.0	$0.0	$6.3	1,248	2
4	5004/5005 Interface	Interface	500	($14.8)	($22.6)	($3.3)	$4.5	$1.0	$0.8	$2.8	$3.0	$7.5	1,046	586
5	West	Interface	500	($6.5)	($8.1)	($1.2)	$0.3	$0.0	$0.0	$0.1	$0.1	$0.5	904	28
6	Wylie Ridge	Transformer	AP	$5.7	$9.4	$3.7	($0.0)	($0.0)	($0.3)	($3.1)	($2.8)	($2.8)	3,684	708
7	Yukon	Transformer	AP	$3.2	($0.0)	$0.1	$3.3	($0.1)	$0.1	$0.1	($0.1)	$3.2	468	78
8	AEP-DOM	Interface	500	($0.8)	($3.7)	($0.1)	$2.8	$0.0	$0.0	$0.3	$0.3	$3.1	1,810	196
9	Gore - Hampshire	Line	AP	($0.7)	($1.5)	($0.2)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	622	0
10	Wolfcreek	Transformer	AEP	$2.4	$3.9	$0.4	($1.1)	($0.2)	($0.2)	($0.3)	($0.3)	($1.4)	2,514	256
11	Dickerson - Quince Orchard	Line	Pepco	($5.4)	($4.0)	($0.8)	($2.2)	($0.8)	($0.2)	$1.2	$0.6	($1.6)	210	118
12	Cloverdale - Lexington	Line	AEP	$0.4	($0.5)	$0.2	$1.1	$0.2	$0.0	($0.7)	($0.5)	$0.6	896	650
13	Carnegie - Tidd	Line	AECO	$1.5	$0.3	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	1,704	0
14	Danville - East Danville	Line	AEP	$0.2	($0.9)	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	2,516	0
15	Tiltonsville - Windsor	Line	AP	$1.6	$0.4	$0.2	$1.4	($0.1)	($0.0)	($0.2)	($0.3)	$1.1	1,038	104
18	Bedington	Transformer	AP	$0.2	($0.7)	($0.1)	$0.8	($0.0)	$0.0	$0.0	($0.0)	$0.8	50	10
19	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.3	$0.9	($0.2)	($0.8)	($0.8)	0	110
21	Hamilton - Weirton	Line	AP	$0.9	$0.3	$0.1	$0.8	$0.0	($0.0)	($0.0)	($0.0)	$0.8	300	6
22	Doubs	Transformer	AP	$0.3	($0.3)	($0.0)	$0.6	$0.1	$0.1	$0.1	$0.1	$0.7	82	102
23	Butler - Karns City	Line	AP	$1.4	$0.9	($0.1)	$0.4	($0.1)	($0.3)	$0.0	$0.3	$0.7	738	88

Table 7-48 AP Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-46)

				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	($20.3)	($77.3)	($5.6)	$51.4	$3.6	$3.8	$6.0	$5.7	$57.2	4,180	2,020
2	Bedington - Black Oak	Interface	500	($7.4)	($26.6)	($1.0)	$18.3	$0.3	$0.4	$0.1	($0.1)	$18.2	2,656	86
3	Doubs	Transformer	AP	$4.1	($5.9)	($0.3)	$9.7	$1.6	$1.1	$0.4	$0.9	$10.6	1,830	566
4	AEP-DOM	Interface	500	($2.1)	($7.8)	$0.4	$6.0	$0.3	($0.2)	($0.1)	$0.4	$6.4	942	168
5	Tiltonsville - Windsor	Line	AP	$6.6	$1.5	$0.6	$5.7	($0.9)	($0.2)	($0.7)	($1.4)	$4.3	3,128	540
6	5004/5005 Interface	Interface	500	($10.0)	($14.9)	($0.7)	$4.3	$0.7	$1.2	$0.5	$0.0	$4.3	2,100	734
7	Mount Storm - Pruntytown	Line	AP	($0.3)	($1.6)	($0.0)	$1.3	$1.1	($0.4)	$0.5	$2.0	$3.2	174	488
8	Cloverdale - Lexington	Line	AEP	$0.7	($1.4)	$0.5	$2.6	($0.0)	$0.4	($1.3)	($1.8)	$0.8	1,156	686
9	Belmont	Transformer	AP	$2.1	($0.5)	$0.1	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	688	18
10	Fort Martin - Ronco	Line	AP	$0.2	$0.2	$0.1	$0.2	($0.2)	$0.9	($1.4)	($2.5)	($2.3)	62	84
11	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	$1.1	$0.9	($0.1)	($0.2)	62	202
12	Halfway - Marlowe	Line	AP	$0.6	($0.7)	($0.0)	$1.3	$0.1	($0.1)	$0.0	$0.2	$1.5	120	36
13	Nipetown - Reid	Line	AP	($0.1)	($1.7)	$0.0	$1.6	$0.1	$0.2	($0.0)	($0.1)	$1.6	422	98
14	Endless Caverns	Transformer	Dominion	$1.3	$0.0	$0.2	$1.6	$0.0	$0.0	($0.0)	($0.0)	$1.5	566	6
15	Middlebourne - Willow	Line	AP	$1.3	($0.2)	$0.2	$1.7	($0.2)	($0.0)	($0.2)	($0.4)	$1.4	440	146
16	Reid - Ringgold	Line	AP	($3.3)	($3.3)	($0.3)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	540	30
17	Albright - Snowy Creek	Line	AP	$0.9	($0.3)	$0.0	$1.2	$0.0	($0.0)	($0.0)	$0.0	$1.2	498	4
19	Yukon	Transformer	AP	$1.2	$0.1	$0.1	$1.2	$0.0	$0.1	$0.1	($0.0)	$1.2	160	26
20	Boonsboro - Marlowe	Line	AP	($0.2)	($0.5)	($0.0)	$0.2	$0.4	$0.7	$0.2	($0.1)	$0.1	94	68
21	Messic Road - Morgan	Line	AP	($0.8)	($1.6)	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	676	0

ATSI Control Zone

Table 7-49 ATSI Control Zone top congestion cost impacts (By facility): June 2011 (New table)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($6.2)	($2.4)	($0.1)	($3.9)	($1.0)	$0.7	$0.3	($1.5)	($5.3)	4,090	1,258
2	Dickerson - Quince Orchard	Line	Pepco	($2.9)	($1.2)	$0.0	($1.7)	($0.8)	$0.4	$0.0	($1.2)	($2.9)	210	118
3	West	Interface	500	($3.8)	($1.8)	($0.0)	($2.0)	$0.0	$0.0	$0.0	$0.0	($2.0)	904	28
4	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	($0.6)	$0.5	$0.5	($0.6)	($0.6)	0	110
5	Bayshore - Jeep	Line	ATSI	$0.9	($0.2)	$0.0	$1.1	$0.6	$0.2	$0.0	$0.4	$1.5	32	12
6	AEP-DOM	Interface	500	($2.1)	($0.8)	($0.0)	($1.3)	$0.0	$0.0	$0.0	$0.0	($1.3)	1,810	196
7	Danville - East Danville	Line	AEP	($1.8)	($0.5)	($0.0)	($1.3)	$0.0	$0.0	$0.0	$0.0	($1.3)	2,516	0
8	Clover	Transformer	Dominion	($0.7)	($0.2)	$0.0	($0.5)	($0.2)	$0.2	($0.1)	($0.4)	($0.9)	1,086	492
9	Wylie Ridge	Transformer	AP	($2.1)	($1.4)	($0.1)	($0.8)	$0.0	$0.0	$0.0	$0.0	($0.8)	3,684	708
10	5004/5005 Interface	Interface	500	($0.0)	($0.0)	($0.0)	($0.0)	($0.4)	$0.2	$0.0	($0.5)	($0.5)	1,046	586
11	Nottingham - Nottingham	Line	ATSI	$0.5	($0.1)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	12	0
12	Jeep - Dixie	Line	ATSI	$0.5	($0.1)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	28	0
13	Michigan City - Laporte	Flowgate	MISO	$0.7	$0.3	$0.1	$0.5	$0.1	$0.0	($0.1)	($0.0)	$0.5	1,704	552
14	Gore - Hampshire	Line	AP	($0.9)	($0.4)	($0.0)	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	622	0
15	Beaver - Sammis	Line	DLCO	($0.2)	($0.7)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	124	22
20	Galion – GM Mansfield	Line	ATSI	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	30	0
52	West Akron - Aetna	Line	ATSI	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2	0
64	Brookside - Wellington	Line	ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	38	0
66	Sammis - Wylie Ridge	Line	ATSI	($0.1)	($0.1)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	66	0
91	Lakeview - Greenfoe	Line	ATSI	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	2

ComEd Control Zone

Table 7-50 ComEd Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-47)

				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	Crete - St Johns Tap	Flowgate	MISO	($43.9)	($64.7)	($11.9)	$9.0	$3.8	$2.3	$4.6	$6.2	$15.1	4,190	1,210
2	AP South	Interface	500	($36.5)	($46.4)	($0.7)	$9.1	$4.9	$1.0	$0.2	$4.2	$13.3	4,090	1,258
3	Electric Jct - Nelson	Line	ComEd	$0.9	($12.5)	$3.0	$16.4	$0.8	$2.8	($3.9)	($5.9)	$10.5	2,018	112
4	5004/5005 Interface	Interface	500	($20.9)	($27.0)	($0.4)	$5.7	$1.9	$0.8	$0.4	$1.5	$7.2	1,046	586
5	Bunsonville - Eugene	Flowgate	MISO	($10.1)	($17.1)	($0.2)	$6.8	$0.0	$0.0	$0.0	$0.0	$6.8	2,328	0
6	Oak Grove - Galesburg	Flowgate	MISO	($0.9)	($7.3)	$3.1	$9.5	($0.4)	$2.0	($6.1)	($8.5)	$0.9	1,782	836
7	Wylie Ridge	Transformer	AP	($15.3)	($20.0)	($0.1)	$4.6	$1.5	$0.3	($0.1)	$1.1	$5.7	3,684	708
8	East Frankfort - Crete	Line	ComEd	($8.3)	($12.5)	($1.0)	$3.2	$0.0	($0.0)	$0.0	$0.0	$3.2	1,462	14
9	Rising	Flowgate	MISO	($6.9)	($10.8)	($0.4)	$3.5	($0.0)	$0.6	($0.3)	($0.9)	$2.6	994	190
10	Pleasant Prairie - Zion	Flowgate	MISO	$0.2	($0.7)	$1.9	$2.7	($0.0)	($0.0)	($5.7)	($5.7)	($3.0)	1,212	288
11	Crete - St. Johns	Flowgate	MISO	($5.7)	($9.0)	($0.8)	$2.4	$0.0	$0.0	$0.0	$0.0	$2.4	698	0
12	West	Interface	500	($8.7)	($11.3)	($0.1)	$2.6	$0.1	$0.0	$0.0	$0.1	$2.6	904	28
13	Lakeview - Pleasant Prairie	Flowgate	MISO	$0.2	$0.1	$0.2	$0.3	($0.1)	$0.0	($3.6)	($3.7)	($3.4)	48	348
14	Michigan City - Laporte	Flowgate	MISO	($7.5)	($8.6)	$0.5	$1.6	$1.1	($0.3)	($0.1)	$1.2	$2.8	1,704	552
15	AEP-DOM	Interface	500	($7.7)	($9.6)	($0.4)	$1.5	$0.3	$0.0	$0.2	$0.4	$1.9	1,810	196
19	Belvidere - Woodstock	Line	ComEd	$0.1	($2.2)	$0.3	$2.7	$0.0	$0.1	($0.2)	($0.2)	$2.5	324	36
21	Pleasant Valley - Belvidere	Line	ComEd	($0.2)	($2.9)	$0.6	$3.2	$0.1	$0.6	($0.5)	($1.0)	$2.2	634	194
23	Cherry Valley	Transformer	ComEd	$0.8	($1.3)	$0.4	$2.5	$0.0	$0.0	($0.1)	($0.1)	$2.3	736	20
28	Nelson - Cordova	Line	ComEd	$0.9	($0.7)	$0.9	$2.5	($0.1)	$0.2	($1.1)	($1.4)	$1.1	798	62
31	Waukegan - Zion	Line	ComEd	$0.2	($0.4)	$1.2	$1.7	($0.0)	$0.0	($0.2)	($0.2)	$1.5	1,106	8

Table 7-51 ComEd Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-48)

				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	East Frankfort - Crete	Line	ComEd	($22.8)	($44.1)	($2.0)	$19.4	($2.3)	$0.5	$0.1	($2.6)	$16.8	3,300	1,208
2	AP South	Interface	500	($44.3)	($63.5)	($0.3)	$18.8	($1.7)	($0.0)	($0.1)	($1.7)	$17.1	4,180	2,020
3	Pleasant Valley - Belvidere	Line	ComEd	($2.5)	($12.7)	$0.8	$11.0	($0.0)	$2.0	($1.1)	($3.1)	$7.9	2,554	440
4	5004/5005 Interface	Interface	500	($12.8)	($20.2)	($0.0)	$7.4	($0.6)	($0.3)	($0.0)	($0.3)	$7.1	2,100	734
5	Bedington - Black Oak	Interface	500	($18.2)	($24.8)	($0.0)	$6.5	($0.2)	$0.1	($0.0)	($0.3)	$6.2	2,656	86
6	AEP-DOM	Interface	500	($10.3)	($16.3)	($0.4)	$5.6	($0.1)	($0.2)	$0.0	$0.1	$5.7	942	168
7	Electric Jct - Nelson	Line	ComEd	$0.4	($5.1)	$1.3	$6.8	$0.2	$0.5	($1.6)	($1.8)	$5.0	786	152
8	Pleasant Prairie - Zion	Flowgate	MISO	$0.3	($3.2)	$1.1	$4.6	$0.4	$0.9	($3.6)	($4.1)	$0.5	1,890	348
9	Crete - St Johns Tap	Flowgate	MISO	($5.3)	($8.8)	($0.1)	$3.4	($0.2)	($0.1)	($0.2)	($0.3)	$3.2	660	164
10	Rising	Flowgate	MISO	($2.2)	($6.9)	($0.0)	$4.7	($0.0)	($0.0)	$0.0	$0.0	$4.7	1,552	72
11	Waterman - West Dekalb	Line	ComEd	($0.9)	($4.6)	$0.4	$4.1	$0.4	$0.3	($0.1)	($0.1)	$4.1	2,992	446
12	Cloverdale - Lexington	Line	AEP	($4.7)	($7.6)	($0.1)	$2.8	($0.6)	$0.2	$0.1	($0.7)	$2.1	1,156	686
13	Doubs	Transformer	AP	($6.7)	($8.8)	($0.0)	$2.1	($0.3)	$0.3	$0.0	($0.6)	$1.5	1,830	566
14	Tiltonsville - Windsor	Line	AP	($4.1)	($6.1)	($0.0)	$2.0	($0.0)	$0.0	$0.0	($0.0)	$2.0	3,128	540
15	Wilton Center	Transformer	ComEd	($2.3)	($3.7)	$0.2	$1.6	($0.3)	$0.8	($0.9)	($2.1)	($0.5)	290	180
21	Glidden - West Dekalb	Line	ComEd	$0.0	($0.9)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	370	0
24	Cherry Valley	Transformer	ComEd	$0.3	($0.4)	$0.1	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.7	50	6
25	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.6	($0.0)	($0.7)	($0.7)	0	164
30	Davis	Transformer	ComEd	$0.1	($0.4)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	110	0
32	Belvidere - Woodstock	Line	ComEd	$0.2	($0.2)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	98	0

DAY Control Zone

Table 7-52 DAY Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-49)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pierce - East Bend	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.9)	($0.8)	($0.8)	0	26
2	Danville - East Danville	Line	AEP	($0.3)	($0.9)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	2,516	0
3	AEP-DOM	Interface	500	($0.6)	($1.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,810	196
4	West	Interface	500	($0.6)	($1.1)	($0.0)	$0.5	$0.0	($0.0)	$0.0	$0.0	$0.5	904	28
5	AP South	Interface	500	($2.7)	($3.4)	($0.3)	$0.4	$0.3	$0.8	$0.3	($0.3)	$0.2	4,090	1,258
6	Wylie Ridge	Transformer	AP	($1.1)	($1.5)	($0.1)	$0.2	$0.1	$0.2	$0.1	($0.1)	$0.2	3,684	708
7	Wolfcreek	Transformer	AEP	($0.2)	($0.4)	($0.0)	$0.3	$0.0	$0.0	$0.0	($0.0)	$0.3	2,514	256
8	Bedington - Black Oak	Interface	500	($0.5)	($0.7)	($0.0)	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	1,248	2
9	Dickerson - Quince Orchard	Line	Pepco	($0.4)	($0.5)	($0.0)	$0.1	$0.2	$0.0	$0.0	$0.1	$0.2	210	118
10	Clover	Transformer	Dominion	($0.2)	($0.4)	$0.0	$0.2	$0.1	$0.1	($0.0)	($0.0)	$0.2	1,086	492
11	Pierce - Foster	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.2)	($0.2)	0	8
12	Susquehanna	Transformer	PPL	($0.1)	($0.3)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	240	0
13	5004/5005 Interface	Interface	500	($1.6)	($1.6)	($0.0)	($0.0)	$0.1	$0.4	$0.1	($0.2)	($0.2)	1,046	586
14	Crete - St Johns Tap	Flowgate	MISO	$0.5	$0.6	($0.1)	($0.2)	($0.0)	($0.0)	($0.0)	($0.0)	($0.2)	4,190	1,210
15	Cloverdale - Lexington	Line	AEP	($0.2)	($0.3)	$0.0	$0.1	$0.1	$0.4	($0.0)	($0.3)	($0.2)	896	650
84	Foster2 - Pierce	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	2

Table 7-53 DAY Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-50)

				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	($2.6)	($4.1)	($0.4)	$1.1	$0.0	$0.5	$0.4	($0.0)	$1.0	4,180	2,020
2	5004/5005 Interface	Interface	500	($0.7)	($1.6)	($0.0)	$0.9	$0.1	$0.1	$0.1	$0.0	$0.9	2,100	734
3	AEP-DOM	Interface	500	($0.7)	($1.4)	($0.0)	$0.7	($0.0)	($0.0)	$0.0	$0.0	$0.7	942	168
4	Bedington - Black Oak	Interface	500	($0.9)	($1.6)	($0.2)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.4	2,656	86
5	Cloverdale - Lexington	Line	AEP	($0.2)	($0.6)	($0.1)	$0.4	$0.0	$0.0	$0.1	$0.1	$0.5	1,156	686
6	Pleasant Prairie - Zion	Flowgate	MISO	$0.0	($0.0)	$0.3	$0.4	($0.0)	$0.0	($0.8)	($0.8)	($0.5)	1,890	348
7	Electric Jct - Nelson	Line	ComEd	$0.0	$0.0	$1.1	$1.1	$0.0	$0.0	($1.5)	($1.5)	($0.4)	786	152
8	Doubs	Transformer	AP	($0.3)	($0.6)	($0.0)	$0.2	$0.1	$0.1	$0.0	$0.0	$0.3	1,830	566
9	Tiltonsville - Windsor	Line	AP	($0.2)	($0.4)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.1	$0.2	3,128	540
10	Dumont - Stillwell	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.2)	($0.2)	($0.2)	32	68
11	Fort Martin - Ronco	Line	AP	($0.0)	($0.1)	($0.0)	$0.0	($0.0)	$0.0	$0.2	$0.2	$0.2	62	84
12	Danville - East Danville	Line	Dominion	($0.2)	($0.5)	($0.2)	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	1,758	170
13	Mount Storm - Pruntytown	Line	AP	($0.0)	($0.1)	($0.0)	$0.0	$0.1	$0.1	$0.2	$0.2	$0.2	174	488
14	Waterman - West Dekalb	Line	ComEd	$0.0	$0.0	$0.3	$0.3	$0.0	$0.0	($0.1)	($0.1)	$0.2	2,992	446
15	Branchburg - Flagtown	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	($0.2)	0	0

DLCO Control Zone

Table 7-54 DLCO Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-51)

				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	Wylie Ridge	Transformer	AP	($9.4)	($14.7)	($0.4)	$4.8	($0.4)	($0.1)	$0.2	($0.1)	$4.7	3,684	708
2	AP South	Interface	500	($11.1)	($14.8)	($0.4)	$3.4	($1.1)	($0.2)	$0.3	($0.6)	$2.7	4,090	1,258
3	5004/5005 Interface	Interface	500	($5.3)	($6.9)	($0.1)	$1.5	($0.4)	($0.0)	$0.1	($0.3)	$1.2	1,046	586
4	Collier - Elwyn	Line	DLCO	$1.8	($0.2)	$0.0	$2.0	$0.1	$0.1	($0.0)	($0.0)	$1.9	504	60
5	Crescent	Transformer	DLCO	$1.1	($0.1)	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	220	0
6	Bedington - Black Oak	Interface	500	($1.7)	($2.3)	($0.0)	$0.6	($0.0)	($0.0)	$0.0	($0.0)	$0.6	1,248	2
7	AEP-DOM	Interface	500	($1.2)	($1.8)	$0.0	$0.6	($0.0)	($0.0)	$0.0	($0.0)	$0.6	1,810	196
8	West	Interface	500	($2.0)	($2.4)	($0.0)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.4	904	28
9	Crete - St Johns Tap	Flowgate	MISO	$1.3	$1.7	$0.1	($0.4)	$0.1	$0.0	($0.0)	$0.0	($0.4)	4,190	1,210
10	Yukon	Transformer	AP	$1.1	$0.8	$0.1	$0.3	$0.1	($0.2)	($0.0)	$0.2	$0.6	468	78
11	Beaver - Sammis	Line	DLCO	($0.3)	($0.6)	($0.0)	$0.4	($0.1)	$0.1	$0.0	($0.2)	$0.2	124	22
12	South Mahwah - Waldwick	Line	PSEG	($0.7)	($0.9)	$0.1	$0.3	($0.1)	$0.0	($0.1)	($0.3)	$0.0	5,886	838
13	Danville - East Danville	Line	AEP	($0.5)	($0.8)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	2,516	0
14	Cloverdale - Lexington	Line	AEP	($0.2)	($0.3)	$0.0	$0.1	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	896	650
15	Butler - Karns City	Line	AP	($0.4)	($0.6)	($0.0)	$0.2	($0.0)	($0.0)	$0.0	($0.0)	$0.2	738	88
17	Arsenal - Brunot Island	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	22	16
24	Arsenal - Oakland	Line	DLCO	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	48	12
27	Arsenal	Transformer	DLCO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	34	0
58	Dravosburg	Transformer	DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	86	0
100	Arsenal - Highland	Line	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0

Table 7-55 DLCO Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-52)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$10.1	($0.1)	$0.2	$10.4	$0.1	($0.5)	($0.3)	$0.3	$10.7	1,158	248
2	AP South	Interface	500	($27.9)	($33.6)	($0.1)	$5.5	($1.7)	($0.5)	$0.2	($1.0)	$4.5	4,180	2,020
3	Collier - Elwyn	Line	DLCO	$3.7	$0.4	$0.1	$3.4	($0.0)	($0.1)	($0.0)	$0.1	$3.4	686	188
4	5004/5005 Interface	Interface	500	($7.8)	($9.5)	($0.1)	$1.6	($0.4)	($0.1)	$0.0	($0.2)	$1.4	2,100	734
5	Bedington - Black Oak	Interface	500	($9.3)	($10.9)	($0.1)	$1.5	($0.2)	($0.1)	$0.0	($0.1)	$1.4	2,656	86
6	AEP-DOM	Interface	500	($4.3)	($5.7)	($0.0)	$1.4	($0.2)	($0.1)	$0.0	($0.1)	$1.3	942	168
7	Sammis - Wylie Ridge	Line	AP	($1.7)	($3.1)	($0.0)	$1.4	($0.1)	$0.1	$0.0	($0.2)	$1.2	988	88
8	East Frankfort - Crete	Line	ComEd	$0.9	$1.5	($0.0)	($0.7)	$0.1	($0.0)	($0.0)	$0.1	($0.6)	3,300	1,208
9	Carson - Oakland	Line	DLCO	$0.7	$0.0	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	80	0
10	Doubs	Transformer	AP	($1.8)	($2.2)	($0.0)	$0.4	($0.2)	$0.0	($0.0)	($0.3)	$0.1	1,830	566
11	Cloverdale - Lexington	Line	AEP	($0.7)	($1.1)	$0.0	$0.4	($0.2)	($0.0)	($0.0)	($0.2)	$0.2	1,156	686
12	Collier	Transformer	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	16	16
13	Mount Storm - Pruntytown	Line	AP	($0.7)	($0.9)	($0.0)	$0.2	($0.4)	($0.1)	$0.0	($0.3)	($0.1)	174	488
14	Danville - East Danville	Line	Dominion	($0.9)	($1.0)	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	1,758	170
15	Reid - Ringgold	Line	AP	($0.5)	($0.6)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	540	30
17	Crescent - Sewickly	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
18	Beaver - Sammis	Line	DLCO	($0.2)	($0.4)	($0.0)	$0.2	($0.1)	$0.3	$0.0	($0.3)	($0.1)	330	72
20	Beaver	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.0)	($0.1)	($0.1)	0	14
39	Beaver - Mansfield	Line	DLCO	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	92	0
45	Brunot Island - Collier	Line	DLCO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4	0

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-56 Dominion Control Zone top congestion cost impacts (By facility): January through June 2011 (See 2010 SOM, Table 7-53)

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
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	$37.1	($23.2)	$2.2	$62.6	$0.3	$2.9	($2.2)	($4.7)	$57.9	4,090	1,258
2	Dooms	Transformer	Dominion	$1.3	($0.0)	$0.2	$1.5	($3.7)	$0.2	($2.7)	($6.6)	($5.1)	86	170
3	Clover	Transformer	Dominion	$4.0	($3.9)	$1.9	$9.9	($0.7)	$1.0	($3.6)	($5.3)	$4.6	1,086	492
4	Hopewell - Chesterfield	Line	Dominion	$3.4	$0.2	$0.3	$3.5	($0.5)	($1.3)	($2.0)	($1.2)	$2.3	308	126
5	Cloverdale - Lexington	Line	AEP	$3.4	$0.6	$0.7	$3.4	($0.3)	($0.8)	($1.5)	($1.1)	$2.4	896	650
6	Danville - East Danville	Line	AEP	$6.2	$2.4	$0.5	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	2,516	0
7	AEP-DOM	Interface	500	$6.0	$2.9	$1.2	$4.3	($0.1)	($0.2)	($0.1)	($0.1)	$4.2	1,810	196
8	Dickerson - Quince Orchard	Line	Pepco	($5.3)	($2.4)	($0.8)	($3.7)	$0.3	$0.8	$1.2	$0.7	($3.0)	210	118
9	Bedington - Black Oak	Interface	500	$6.1	$2.9	$0.5	$3.8	($0.0)	($0.0)	($0.0)	($0.0)	$3.8	1,248	2
10	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.7)	($2.5)	($2.5)	($2.5)	0	110
11	Chaparral - Carson	Line	Dominion	$0.6	($0.1)	$0.5	$1.2	($0.2)	$1.2	($2.9)	($4.4)	($3.2)	392	360
12	Valley	Transformer	Dominion	$2.7	$0.0	$0.3	$2.9	($0.0)	($0.0)	($0.0)	($0.0)	$2.9	200	12
13	Wylie Ridge	Transformer	AP	$4.2	$2.2	$0.8	$2.8	$0.0	($0.2)	($0.5)	($0.3)	$2.5	3,684	708
14	Crete - St Johns Tap	Flowgate	MISO	$3.6	$1.6	$0.1	$2.0	($0.2)	($0.2)	($0.1)	($0.0)	$2.0	4,190	1,210
15	Danville - East Danville	Line	Dominion	$0.0	$0.0	$0.0	$0.0	($0.6)	($1.2)	($0.6)	($0.0)	($0.0)	0	568
16	Elmont	Transformer	Dominion	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.3)	($0.8)	($0.5)	($0.4)	20	50
18	Bristers - Ox	Line	Dominion	($0.1)	($1.6)	$0.0	$1.5	$0.2	$0.2	($0.0)	($0.0)	$1.4	66	50
19	Powhatan - Bremo	Line	Dominion	$0.9	($0.2)	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	60	0
22	Beechwood - Kerr Dam	Line	Dominion	$0.4	($0.6)	($0.0)	$1.0	($0.1)	$0.1	($0.0)	($0.2)	$0.8	332	76
26	Halifax - Halifax	Line	Dominion	$0.1	($0.1)	$0.1	$0.2	($0.0)	($0.2)	($0.2)	($0.0)	$0.2	126	62

Table 7-57 Dominion Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2010 SOM, Table 7-54)

				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	$51.4	($27.3)	$1.4	$80.0	$1.9	$5.3	($1.0)	($4.4)	$75.6	4,180	2,020
2	Cloverdale - Lexington	Line	AEP	$7.4	$2.0	$0.8	$6.3	($1.1)	($1.5)	($1.6)	($1.3)	$5.0	1,156	686
3	Bedington - Black Oak	Interface	500	$17.0	$11.2	$1.9	$7.7	($0.2)	($0.1)	($0.3)	($0.3)	$7.5	2,656	86
4	Pleasant View	Transformer	Dominion	$0.3	$0.0	$0.0	$0.3	($4.2)	$1.4	($0.6)	($6.2)	($6.0)	62	202
5	Doubs	Transformer	AP	($1.2)	($5.6)	($0.0)	$4.4	$1.1	$0.3	$0.2	$1.0	$5.4	1,830	566
6	Ox - Francona	Line	Dominion	$3.3	($0.6)	$0.0	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	132	0
7	Ox - Glebe	Line	Dominion	$2.5	($0.7)	$0.0	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	60	0
8	Mount Storm - Pruntytown	Line	AP	$1.4	$1.0	$0.1	$0.5	($1.4)	($1.7)	($1.4)	($1.1)	($0.6)	174	488
9	AEP-DOM	Interface	500	$14.9	$12.1	$0.6	$3.4	($0.1)	($0.3)	($0.1)	$0.1	$3.5	942	168
10	Doubs - Pleasant View	Line	AP	$0.6	$0.1	$0.1	$0.6	($0.7)	($1.5)	($0.7)	$0.0	$0.6	48	40
11	Yadkin	Transformer	Dominion	$1.5	$0.1	$0.0	$1.5	$0.4	$0.0	($0.1)	$0.3	$1.7	52	42
12	Pleasant View	Line	Dominion	$1.8	$0.1	$0.1	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	64	0
13	Greenwich - Elizabeth River	Line	Dominion	$1.6	($0.2)	$0.0	$1.8	$0.0	$0.0	($0.0)	($0.0)	$1.8	64	26
14	Endless Caverns	Transformer	Dominion	$0.3	($0.7)	$0.0	$1.1	($0.0)	($0.0)	$0.0	$0.0	$1.1	566	6
15	East Frankfort - Crete	Line	ComEd	$2.6	$1.3	$0.2	$1.4	($0.2)	($0.3)	($0.2)	($0.0)	$1.4	3,300	1,208
17	Hollymead - Charlottesville	Line	Dominion	$0.0	$0.0	$0.0	$0.0	$0.0	($0.5)	($0.0)	$0.6	$0.6	0	86
19	Danville - East Danville	Line	Dominion	$3.8	$2.5	($0.1)	$1.2	($0.2)	($0.3)	($0.0)	$0.1	$1.3	1,758	170
20	Beechwood - Kerr Dam	Line	Dominion	$0.8	($0.6)	($0.1)	$1.2	($0.2)	$0.1	$0.0	($0.3)	$1.0	606	296
21	Glebe - Jefferson	Line	Dominion	$0.8	($0.3)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	68	0
22	Chuckatuck - Benns Church	Line	Dominion	$0.9	($0.1)	($0.0)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	58	0

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 have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since 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 the introduction of this auction, FTRs have been available to all transmission service customers and PJM members. Network service and firm point-to-point transmission service customers can take allocated ARRs or 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 June* focuses on the annual ARR allocations, the Annual FTR Auctions and 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 six months of 2011 and there is no limit on FTR demand in any FTR auction.
- Performance was evaluated as competitive because it reflected the interaction between participant 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.
- FTRs were paid at 84.9 percent of the target allocation level for the full 2010 to 2011 planning period and 86.9 percent for the first month of the 2011 to 2012 planning period.

- Total FTR buy bids in the Annual FTR Auction for the 2011 to 2012 planning period increased 88 percent from 1,708,556 MW during the prior planning period to 3,214,678 MW. The Annual FTR Auction for the 2011 to 2012 planning period cleared 341,726 MW, an increase of 48 percent from 231,663 MW during the prior planning period.

- The Annual FTR Auction generated $1,029.6 million of net revenue for all FTRs during the 2011 to 2012 planning period, a decrease of $20.2 million from $1,049.8 million for the 2010 to 2011 planning period.

- In the 2011 to 2012 planning period, 102,476 MW of ARR requests were allocated, compared to 101,843 MW for the 2010 to 2011 planning period.

- Network Service Users and Firm Transmission Customers in the ATSI Control Zone chose to directly allocate 4,189 MW, or 60 percent, of ARRs to FTRs.

- In the 2011 to 2012 planning period, 44.4 percent of ARRs were self-scheduled as FTRs, a 10.2 percentage point decrease from the prior planning period.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through June*, 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. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2011 to 2012 planning period include the Doubs Transformer and the Bartonsville – Stephens City line. Market participants can also sell FTRs. In the Annual FTR Auction for the 2011 to 2012 planning period, total FTR sell offers were 337,510 MW, up from 178,248 MW during the 2010 to 2011 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first month (June 2011) of the 2011 to 2012 planning period, total FTR sell offers were 688,530 MW.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the Annual FTR Auction for the 2011 to 2012 planning period, total FTR buy bids were 3,214,678 MW. This is an 88 percent increase from 1,708,556 MW during the 2010 to 2011 Annual FTR Auction. Total FTR self scheduled bids were 46,017 MW for the 2011 to 2012 planning period, a decrease from 55,732 MW for the 2010 to 2011 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first month (June 2010) of the 2011 to 2012 planning period, total FTR buy bids were 2,180,573 MW.

- **FTR Credit Issues.** There were no participants that defaulted during the first six months of 2011.

- **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. For the 2011 to 2012 planning period, financial entities own 61 percent of prevailing flow Annual cleared buy bid FTRs while financial entities own 81 percent of counter flow Annual cleared buy bid FTRs. Overall, financial entities own 66 percent of all FTRs bought in the Annual Auction. 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 six 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 six months of 2011 to show ownership patterns by FTR direction. Financial entities owned 64 percent of all prevailing and counter flow FTRs, including 59 percent of all prevailing flow FTRs and 76 percent of all counter flow FTRs and during the same time period.

Market Performance

- **Volume.** For the 2011 to 2012 planning period, the Annual FTR Auction cleared 341,726 MW (10.6 percent) of FTR buy bids, up from 231,663 MW (13.6 percent) for the 2010 to 2011 planning period. The Annual FTR Auction also cleared 24,960 MW (7.4 percent) of FTR sell offers for the 2011 to 2012 planning period, up from 10,315 MW (5.8 percent) for the 2010 to 2011 planning period. For the first month of the 2011 to 2012 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 323,157 MW (14.8 percent) of FTR buy bids and 64,937 MW (9.4 percent) of FTR sell offers.

- **Price.** For the 2011 to 2012 planning period, 87.2 percent of the Annual FTRs were purchased for less than $1 per MWh and 92.3 percent for less than $2 per MWh. For the 2011 to 2012 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.68 per MWh for 24-hour FTRs, $0.44 per MWh for on peak FTRs and $0.28 per MWh for off peak FTRs. Weighted-average prices paid for annual buy-bid FTR obligations for the 2010 to 2011 planning period were $0.43 per MWh for 24-hour FTRs and $0.73 per MWh for on peak FTRs and $0.32 per MWh for off peak FTRs. The weighted-average prices paid for 2011 to 2012 planning period annual buy-bid FTR obligations and options were $0.41 per MWh and $0.16 per MWh, compared to $0.35 per MWh and $0.26 per MWh, in the 2010 to 2011 planning period.[2] The weighted-average price paid for buy bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first month of the 2011 to 2012 planning period was $0.13 per MWh, compared with $0.14 per MWh for the full 12-month 2010 to 2011 planning period.

- **Revenue.** The Annual FTR Auction generated $1,029.6 million of net revenue for all FTRs during the 2011 to 2012 planning period, down from $1,049.8 million for the 2010 to 2011 planning period. The Monthly Balance of Planning Period FTR Auctions generated $5.3 million in net revenue for all FTRs during the first month of the 2011 to 2012 planning period. This is a $2.8 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 86.9 percent of the target allocation level for the first month of the 2011 to 2012 planning period. 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.[3] Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $134.6 million of FTR revenues during the first month of the 2011 to 2012 planning period and $1,431.5 million during the 2010 to 2011 planning period. For the full twelve months of the 2010 to 2011 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were the Western Hub and PECO Control Zone.

- **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

2 Weighted-average prices for FTRs in the Long Term FTR Auction, Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak. For example, FTRs in the 2010 to 2011 Annual FTR Auction would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,112 hours) and off peak (4,648 hours).

3 PJM Financial Transmission Rights Task Force (FTRTF), <http://pjm.com/committees-and-groups/task-forces/ftrtf.aspx>.

overall and were profitable for both physical entities and financial entities in the first six 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

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2011 to 2012 planning period were the South Mahwah — Waldwick line and the East Frankfort — Crete line. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- **Demand.** Total demand in the annual ARR allocation was 148,538 MW for the 2011 to 2012 planning period with 64,160 MW bid in Stage 1A, 27,325 MW bid in Stage 1B and 57,053 MW bid in Stage 2. This is up from 135,614 MW for the 2010 to 2011 planning period with 61,793 MW bid in Stage 1A, 27,850 MW bid in Stage 1B and 45,971 MW bid in Stage 2. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- **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 8,243 MW of ARRs associated with approximately $119,800 of revenue that were reassigned in the first month 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

- **Volume.** Of 148,538 MW in ARR requests for the 2011 to 2012 planning period, 102,476 MW (69.0 percent) were allocated. There were 64,160 MW allocated in Stage 1A, 22,208 MW allocated in Stage 1B and 16,108 MW allocated in Stage 2. Eligible market participants self scheduled 46,017 MW (44.4 percent) of these allocated ARRs as Annual FTRs. Of 135,614 MW in ARR requests for the 2010 to 2011 planning period, 101,843 MW (75.1 percent) were allocated. There were 61,793 MW allocated in Stage 1A, 27,850 MW allocated in Stage 1B and 12,200 MW allocated in Stage 2. Eligible market participants self scheduled 55,732 MW (54.6 percent) of these allocated ARRs as Annual FTRs.

  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 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. Network Service Users and Firm Transmission Customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the ATSI Control Zone. During this transitional period, the directly allocated FTRs are reallocated as load shifts between LSEs within the transmission zone. As load shifts from one LSE to another within the transmission zone, a proportionate share of the directly allocated FTRs are shifted by the LSE that loses load to the LSE gaining load. Table 8-25 separately lists the ARR volume for the ATSI Control Zone, which is included in the 2011 to 2012 ARR allocation volume in Table 8-24. Table 8-26 lists the directly allocated FTR volume for the 2011 to 2012 planning period for the ATSI Control Zone, which is not included in the data in Table 8-24 and Table 8-25. Of the 6,959 MW of ARRs that sink in ATSI, 4,189 MW were directly allocated as FTRs rather than allocated as ARRs for the 2011 to 2012 planning period.

- **Revenue.** ARRs receive revenues in the form of credits based on the results of the FTR auctions. During the 2011 to 2012 planning period, ARR holders will receive $982.9 million in ARR credits, with an average hourly ARR credit of $1.09 per MWh.

- **Revenue Adequacy.** During the 2011 to 2012 planning period, the ARR target allocations were $982.9 million while PJM collected $1,070.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through June 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.

- **ARR Proration.** For the 2011 to 2012 planning period, no ARRs were prorated in Stage 1A of the annual ARR allocation. In Stage 1B, the constraints affecting ARR allocation were Electric Junction — Nelson line, AP South Interface and the Cedar Grove — Clifton line. There were 5,117 MW of Stage 1B ARRs denied to participants whose requested ARRs affected those binding constraints. For the 2010 to 2011 planning period, no ARRs were prorated in Stage 1A and Stage 1B of the annual ARR allocation.

- **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 2009 to 2010 planning period, all ARRs and FTRs hedged more than 96.2 percent of the congestion costs within PJM. During the 2010 to 2011 planning period, total ARR and FTR revenues hedged 96.9 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 3.3 percent of the total real time energy charges in the first three 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 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 2010 to 2011 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 month of the 2011 to 2012 planning period were paid at 86.9 percent of the target allocation level. Revenue adequacy for a planning period is not final until the end of the period.

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 across specific paths for which FTRs were available and purchased.

The total of ARR and FTR revenues hedged more than 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. 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

Supply

Table 8-2 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2011 to 2012 (See 2010 SOM, Table 8-3)

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Doubs	Transformer	AP	1	1	1	1
Bartonsville - Stephens City	Line	AP	2	2	NA	NA
Goose Creek - Rising	Flowgate	MISO	3	4	2	2
Tiltonsville - Windsor	Line	AP	4	5	4	3
Nipetown - Reid	Line	AP	5	3	3	4
Bedington - Harmony	Line	AP	13	6	5	5
Bartonsville - Meadowbrook	Line	AP	NA	NA	6	8
Cook - Palisades	Flowgate	MISO	6	9	12	14
Mahans Lane - Tidd	Line	AEP	12	7	7	6
Belmont	Transformer	AP	8	8	8	7

Patterns of Ownership

Table 8-3 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2011 to 2012 (See 2010 SOM, Table 8-5)

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	15.0%	1.4%	11.7%
		No	23.9%	18.0%	22.5%
		Total	38.9%	19.4%	34.2%
	Financial	No	61.0%	80.6%	65.6%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		9.2%	10.4%	9.4%
	Financial		90.8%	89.6%	90.6%
	Total		100.0%	100.0%	100.0%

Table 8-4 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through June 2011 (See 2010 SOM, Table 8-6)

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	12.7%	14.5%	13.2%
	Financial	87.3%	85.5%	86.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	34.8%	23.9%	33.1%
	Financial	65.2%	76.1%	66.9%
	Total	100.0%	100.0%	100.0%

Table 8-5 Daily FTR net position ownership by FTR direction: January through June 2011 (See 2010 SOM, Table 8-7)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	40.7%	24.2%	36.4%
Financial	59.3%	75.8%	63.6%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-6 Annual FTR Auction market volume: Planning period 2011 to 2012 (See 2010 SOM, Table 8-9)

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	85,370	333,758	90,935	27.2%	242,823	72.8%
		Prevailing Flow	289,403	1,756,443	201,338	11.5%	1,555,105	88.5%
		Total	374,773	2,090,201	292,273	14.0%	1,797,928	86.0%
	Options	Counter Flow	0	0	0	0.0%	0	0.0%
		Prevailing Flow	30,614	1,124,477	49,453	4.4%	1,075,024	95.6%
		Total	30,614	1,124,477	49,453	4.4%	1,075,024	95.6%
	Total	Counter Flow	85,370	333,758	90,935	27.2%	242,823	72.8%
		Prevailing Flow	320,017	2,880,920	250,791	8.7%	2,630,129	91.3%
		Total	405,387	3,214,678	341,726	10.6%	2,872,952	89.4%
Self-scheduled bids	Obligations	Counter Flow	249	1,278	1,278	100.0%	0	0.0%
		Prevailing Flow	10,163	44,739	44,739	100.0%	0	0.0%
		Total	10,412	46,017	46,017	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	85,619	335,036	92,213	27.5%	242,823	72.5%
		Prevailing Flow	299,566	1,801,182	246,077	13.7%	1,555,105	86.3%
		Total	385,185	2,136,218	338,290	15.8%	1,797,928	84.2%
	Options	Counter Flow	0	0	0	0.0%	0	0.0%
		Prevailing Flow	30,614	1,124,477	49,453	4.4%	1,075,024	95.6%
		Total	30,614	1,124,477	49,453	4.4%	1,075,024	95.6%
	Total	Counter Flow	85,619	335,036	92,213	27.5%	242,823	72.5%
		Prevailing Flow	330,180	2,925,659	295,530	10.1%	2,630,129	89.9%
		Total	415,799	3,260,695	387,743	11.9%	2,872,952	88.1%
Sell offers	Obligations	Counter Flow	26,728	104,952	4,126	3.9%	100,826	96.1%
		Prevailing Flow	49,422	214,419	20,668	9.6%	193,751	90.4%
		Total	76,150	319,371	24,794	7.8%	294,577	92.2%
	Options	Counter Flow	0	0	0	0.0%	0	0.0%
		Prevailing Flow	823	18,139	166	0.9%	17,973	99.1%
		Total	823	18,139	166	0.9%	17,973	99.1%
	Total	Counter Flow	26,728	104,952	4,126	3.9%	100,826	96.1%
		Prevailing Flow	50,245	232,558	20,834	9.0%	211,724	91.0%
		Total	76,973	337,510	24,960	7.4%	312,550	92.6%

Table 8-7 Comparison of self scheduled FTRs: Planning periods from 2008 to 2009 through 2011 to 2012 (See 2010 SOM, Table 8-10)

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2008/2009	72,851	112,011	65.0%
2009/2010	68,589	109,612	62.6%
2010/2011	55,732	102,046	54.6%
2011/2012	46,017	103,660	44.4%

Table 8-8 Monthly Balance of Planning Period FTR Auction market volume: January through June 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%	84,537	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	847,576	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%	78,905	76.6%
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	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%	78,905	76.6%

* Shows twelve months for 2010/2011; ** Shows one month ended 30-Jun-2011 for 2011/2012

Table 8-9 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January through June 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						169,665
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

Table 8-10 Secondary bilateral FTR market volume: Planning periods 2010 to 2011 and 2011 to 2012[4] (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	292
		On Peak	312
		Off Peak	223
		Total	826
	Option	24-Hour	20
		On Peak	0
		Off Peak	0
		Total	20

* Shows one month ended 30-Jun-2011

4 The 2011 to 2012 planning period covers bilateral FTRs that are effective for any time between June 1, 2011 through June 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 8-11 Annual FTR Auction weighted-average cleared prices (Dollars per MWh): Planning period 2011 to 2012 (See 2010 SOM, Table 8-15)

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.76)	($0.51)	($0.38)	($0.47)
		Prevailing Flow	$1.04	$0.86	$0.62	$0.79
		Total	$0.68	$0.44	$0.28	$0.41
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.89	$0.20	$0.11	$0.16
		Total	$0.89	$0.20	$0.11	$0.16
Self-scheduled bids	Obligations	Counter Flow	($0.11)	NA	NA	($0.11)
		Prevailing Flow	$1.20	NA	NA	$1.20
		Total	$1.16	NA	NA	$1.16
Buy and self-scheduled bids	Obligations	Counter Flow	($0.62)	($0.51)	($0.38)	($0.46)
		Prevailing Flow	$1.15	$0.86	$0.62	$0.91
		Total	$1.00	$0.44	$0.28	$0.58
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.89	$0.20	$0.11	$0.16
		Total	$0.89	$0.20	$0.11	$0.16
Sell offers	Obligations	Counter Flow	($3.16)	($0.70)	($0.61)	($0.87)
		Prevailing Flow	$1.09	$0.71	$0.41	$0.59
		Total	($0.12)	$0.51	$0.21	$0.34
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.00	$2.05	$0.47	$0.75
		Total	$0.00	$2.05	$0.47	$0.75

Figure 8-1 Annual FTR auction clearing price duration curves: Planning period 2011 to 2012 (See 2010 SOM, Figure 8-2)

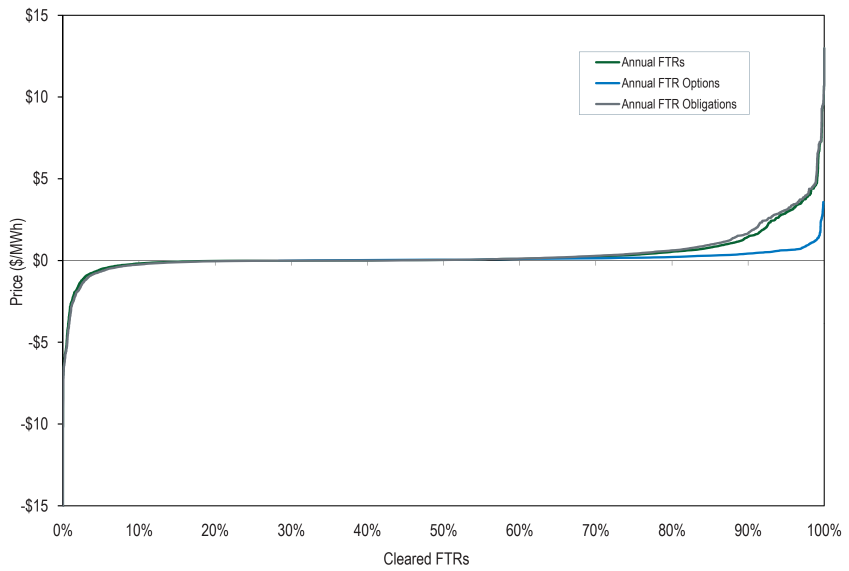


Table 8-12 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January through June 2011 (See 2010 SOM, Table 8-16)

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

Revenue

Annual FTR Auction Revenue

Table 8-13 Annual FTR Auction revenue: Planning period 2011 to 2012 (See 2010 SOM, Table 8-18)

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($31,727,221)	($86,595,481)	($79,270,931)	($197,593,633)
		Prevailing Flow	$173,929,276	$333,218,996	$253,894,947	$761,043,219
		Total	$142,202,056	$246,623,514	$174,624,016	$563,449,586
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,243,985	$19,888,318	$12,943,329	$34,075,631
		Total	$1,243,985	$19,888,318	$12,943,329	$34,075,631
	Total	Counter Flow	($31,727,221)	($86,595,481)	($79,270,931)	($197,593,633)
		Prevailing Flow	$175,173,262	$353,107,313	$266,838,275	$795,118,850
		Total	$143,446,041	$266,511,832	$187,567,345	$597,525,217
Self-scheduled bids	Obligations	Counter Flow	($1,219,303)	NA	NA	($1,219,303)
		Prevailing Flow	$471,940,076	NA	NA	$471,940,076
		Total	$470,720,773	NA	NA	$470,720,773
Buy and self-scheduled bids	Obligations	Counter Flow	($32,946,524)	($86,595,481)	($79,270,931)	($198,812,936)
		Prevailing Flow	$645,869,353	$333,218,996	$253,894,947	$1,232,983,295
		Total	$612,922,829	$246,623,514	$174,624,016	$1,034,170,359
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,243,985	$19,888,318	$12,943,329	$34,075,631
		Total	$1,243,985	$19,888,318	$12,943,329	$34,075,631
	Total	Counter Flow	($32,946,524)	($86,595,481)	($79,270,931)	($198,812,936)
		Prevailing Flow	$647,113,338	$353,107,313	$266,838,275	$1,267,058,926
		Total	$614,166,814	$266,511,832	$187,567,345	$1,068,245,990
Sell offers	Obligations	Counter Flow	($5,147,167)	($5,228,336)	($6,092,443)	($16,467,946)
		Prevailing Flow	$4,479,226	$33,317,024	$16,705,071	$54,501,321
		Total	($667,941)	$28,088,688	$10,612,627	$38,033,375
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$275,150	$294,744	$569,895
		Total	$0	$275,150	$294,744	$569,895
	Total	Counter Flow	($5,147,167)	($5,228,336)	($6,092,443)	($16,467,946)
		Prevailing Flow	$4,479,226	$33,592,175	$16,999,815	$55,071,216
		Total	($667,941)	$28,363,839	$10,907,372	$38,603,270

Figure 8-2 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2011 to 2012 (See 2010 SOM, Figure 8-5)

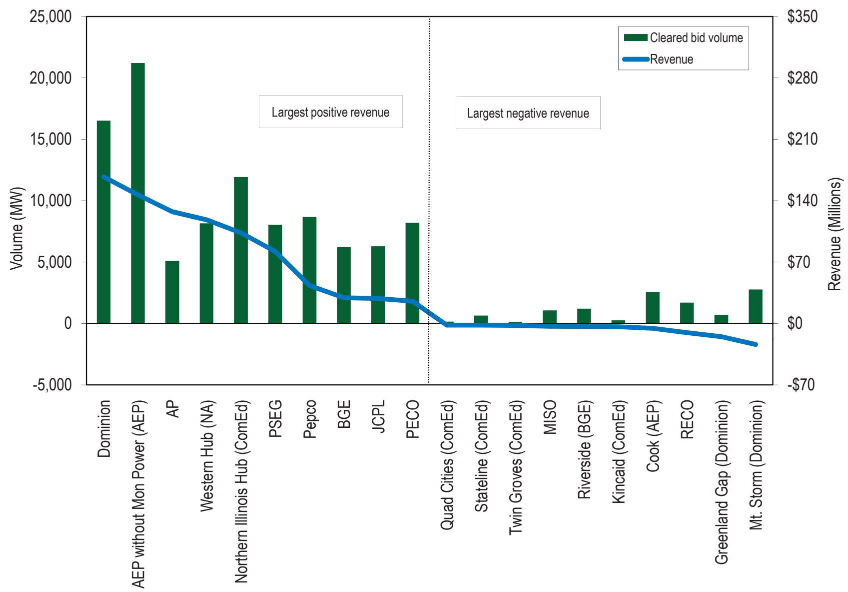
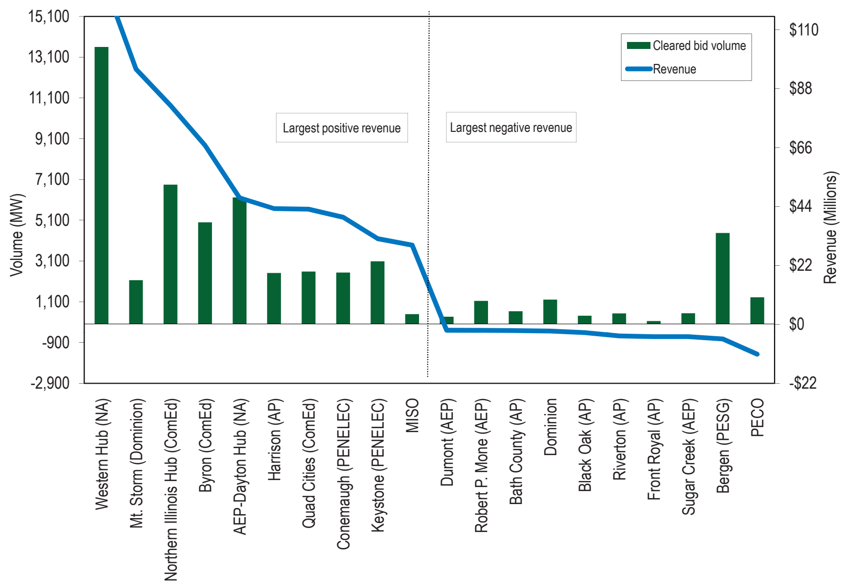


Figure 8-3 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2011 to 2012 (See 2010 SOM, Figure 8-6)



Monthly Balance of Planning Period FTR Auction Revenue

Table 8-14 Monthly Balance of Planning Period FTR Auction revenue: January through June 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
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
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	$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

* Shows twelve months for 2010/2011; ** Shows one month ended 30-Jun-2011 for 2011/2012

Figure 8-4 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2010 to 2011 (See 2010 SOM, Figure 8-7)

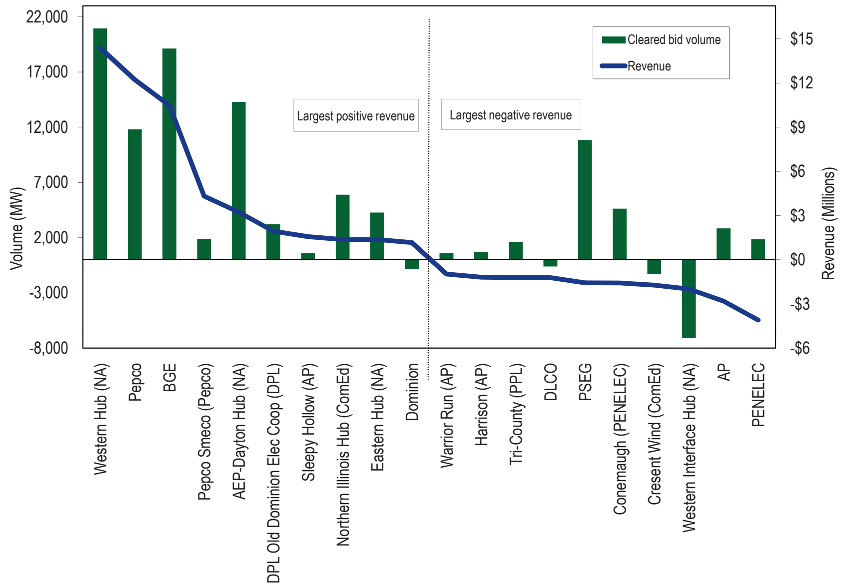
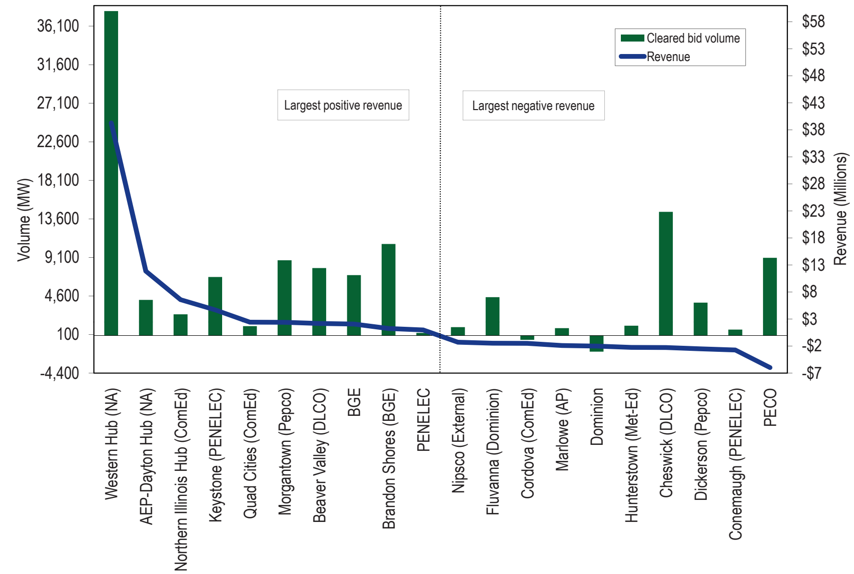


Figure 8-5 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2010 to 2011 (See 2010 SOM, Figure 8-8)



Revenue Adequacy

Table 8-15 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2010 to 2011and 2011 to 2012 (See 2010 SOM, Table 8-20)

Accounting Element	2010/2011	2011/2012*
ARR information		
ARR target allocations	$1,031.0	$80.6
FTR auction revenue	$1,097.8	$89.1
ARR excess	$66.9	$8.5
FTR targets		
FTR target allocations	$1,687.6	$154.8
Adjustments:		
Adjustments to FTR target allocations	($1.8)	$0.0
Total FTR targets	$1,685.8	$154.8
FTR revenues		
ARR excess	$66.9	$8.5
Competing uses	$0.1	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($59.5)	($3.2)
Hourly congestion revenue	$1,464.9	$138.1
MISO M2M (credit to PJM minus credit to MISO)	($47.8)	($8.7)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($0.8)	($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	$134.6
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	$134.6
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,432.3	$134.6
Remaining deficiency	$254.2	$20.3

* Shows one month ended 30-June-11

Table 8-16 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012 through June 30, 2011 (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	97.8%	$194.2	99.0%	($1.9)
Jul-10	$275.0	$273.0	100.0%	$273.0	100.0%	$0.0
Aug-10	$111.3	$119.2	93.2%	$111.3	93.4%	($7.9)
Sep-10	$116.7	$165.3	70.0%	$116.7	70.6%	($48.5)
Oct-10	$52.4	$67.4	77.4%	$52.4	77.8%	($14.9)
Nov-10	$51.5	$80.0	61.9%	$51.5	64.4%	($28.5)
Dec-10	$185.0	$251.1	73.2%	$185.0	73.7%	($66.2)
Jan-11	$245.4	$249.5	98.3%	$245.4	98.4%	($4.0)
Feb-11	$79.4	$93.0	85.0%	$79.4	85.4%	($13.6)
Mar-11	$48.2	$45.6	100.0%	$45.6	100.0%	$0.0
Apr-11	$39.4	$73.2	52.4%	$39.4	53.9%	($33.8)
May-11	$37.5	$72.5	45.1%	$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	$154.8	86.9%	$134.6	86.9%	($20.3)
			Summary for Planning Period 2011 to 2012 through June 30, 2011			
Total	$134.6	$154.8		$134.6	86.9%	($20.3)

Figure 8-6 FTR payout ratio by month: June 2003 to June 2011[5] (See 2010 SOM, Figure 8-9)

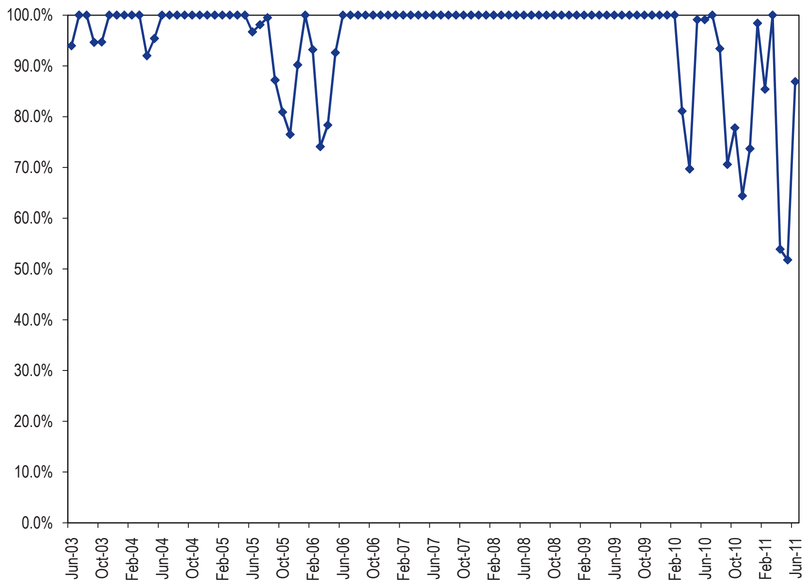


Table 8-17 FTR payout ratio by planning period (See 2010 SOM, Table 8-22)

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*	86.9%

* through June 30, 2011

Figure 8-7 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2010 to 2011 (See 2010 SOM, Figure 8-10)

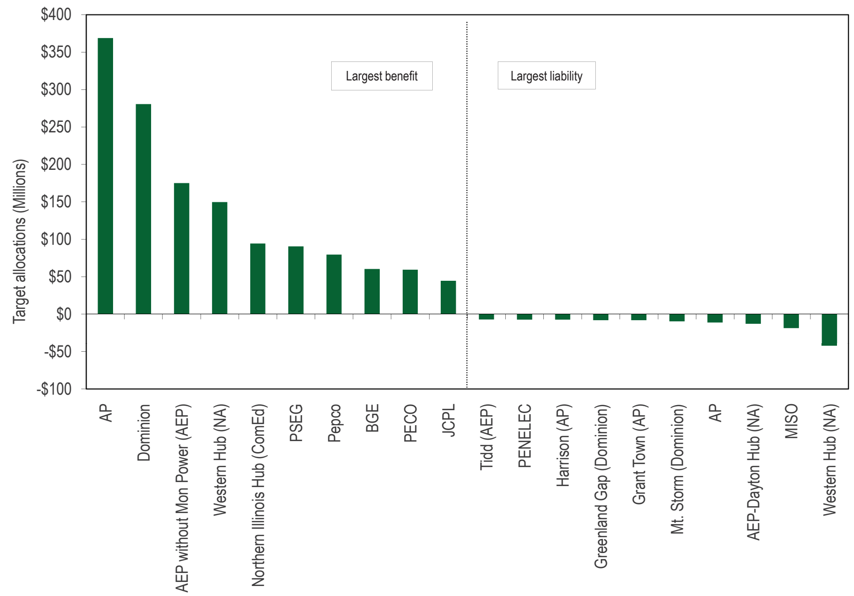
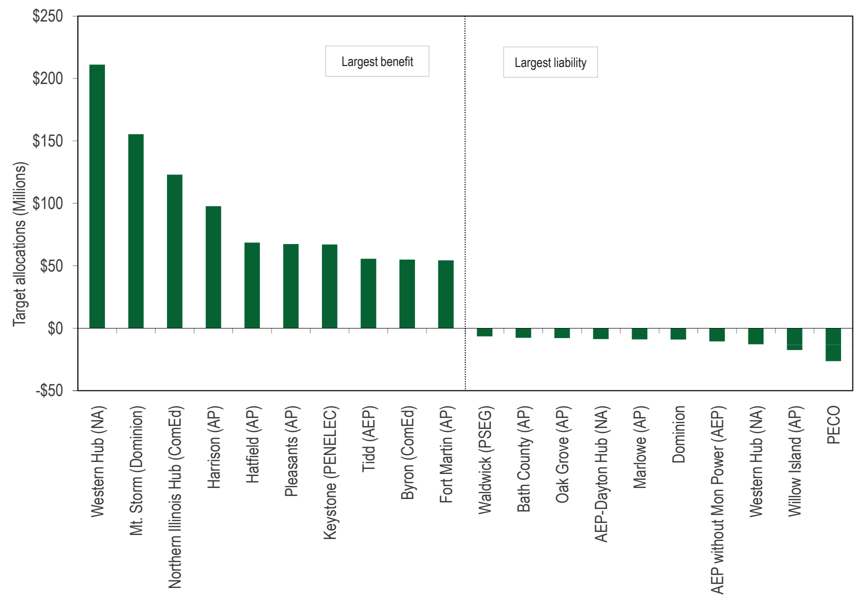


Figure 8-8 Ten largest positive and negative FTR target allocations summed by source: Planning period 2010 to 2011 (See 2010 SOM, Figure 8-11)



5 The underlying data for Figure 8-6 and Table 8-17 is from the "FTR Credit" spreadsheet posted on PJM's website at http://www.pjm.com/markets-and-operations/ftr/revenue-adequacy.aspx and accessed on August 01, 2011.

Profitability

Table 8-18 FTR profits by organization type and FTR direction: January through June 2011 (See 2010 SOM, Table 8-23)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	$243,438,231	$3,587,350	$247,025,581
Financial	$40,872,264	$62,813,556	$103,685,820
Total	$284,310,495	$66,400,906	$350,711,401

Table 8-19 Monthly FTR profits by organization type: January through June 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	$54,836,585	$25,939,839	$80,776,424
Total	$247,025,581	$103,685,820	$350,711,401

Auction Revenue Rights

Market Structure

Supply

Incremental ARRs

Table 8-20 Incremental ARR allocation volume: Planning periods 2008 to 2009 through 2011 to 2012 (See 2010 SOM, Table 8-25)

Planning Period	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	891	891	100%	0	0%
2009/2010	14	531	531	100%	0	0%
2010/2011	14	531	531	100%	0	0%
2011/2012	13	79	79	100%	0	0%

Incremental ARRs (IARRs) for RTEP Upgrades

Table 8-21 IARRs allocated for 2011 to 2012 Annual ARR Allocation for RTEP upgrades[6] (See 2010 SOM, Table 8-26)

		IARR Parameters		
Project #	Project Description	Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	185.2
B0328	TrAIL Project: 502 JCT - Loudoun 500 kV	RTEP B0328 Source	Pepco	388.8
B0329	Carson - Suffolk 500 kV	RTEP B0329 Source	Dominion	93.4

6 The definition of IARR source buses in Table 8-21 are located in the "IARRs for RTEP Upgrades for 2011/12 Planning Period" document posted on PJM's website at <http://www.pjm.com/markets-and-operations/ftr/auction-user-info.aspx#AnnualARR1112>.

Table 8-22 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2011 to 2012 (See 2010 SOM, Table 8-27)

Constraint	Type	Control Zone
South Mahwah - Waldwick	Line	PSEG
East Frankfort - Crete	Line	ComEd
Crete - St. Johns Tap	Flowgate	MISO
Linden - North Ave	Line	PSEG
Bayonne - PVSC	Line	PSEG
Electric Junction - Nelson	Line	ComEd
Bayonne - Marion	Line	PSEG
Pleasant Valley - Belvidere	Line	ComEd
East Sayre - North Waverly	Line	PENELEC
Breed - Wheatland	Line	AEP

Demand

ARR Reassignment for Retail Load Switching

Table 8-23 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2009, through June 30, 2011 (See 2010 SOM, Table 8-28)

	ARRs Reassigned (MW)		ARR Revenue Reassigned [Dollars (Thousands)]	
Control Zone	2010/2011 (12 months)	2011/2012 (1 month)*	2010/2011 (12 months)	2011/2012 (1 month)*
AECO	887	118	$6.0	$1.1
AEP	961	475	$21.4	$9.4
AP	4,992	461	$481.1	$25.3
ATSI	0	1,273	$0.0	$6.6
BGE	3,359	863	$50.5	$14.6
ComEd	3,064	569	$60.2	$10.1
DAY	193	66	$0.6	$0.1
DLCO	1,834	376	$8.6	$1.2
Dominion	0	1	$0.0	$0.0
DPL	1,126	286	$10.2	$2.5
JCPL	3,490	352	$28.8	$2.8
Met-Ed	3,947	593	$51.9	$10.1
PECO	12,284	557	$89.2	$5.8
PENELEC	3,745	516	$53.5	$10.5
Pepco	2,469	468	$27.3	$4.6
PPL	5,734	810	$74.4	$8.4
PSEG	3,416	441	$52.8	$6.5
RECO	143	20	$0.1	$0.0
Total	51,645	8,243	$1,016.5	$119.8

* Through 30-Jun-11

Market Performance

Volume

Table 8-24 Annual ARR allocation volume: Planning periods 2010 to 2011 and 2011 to 2012 (See 2010 SOM, Table 8-29)

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2010/2011	1A	0	8,862	61,793	61,793	100.0%	0	0.0%
	1B	1	3,885	27,850	27,850	100.0%	0	0.0%
	2	2	1,901	15,333	4,161	27.1%	11,172	72.9%
		3	1,374	15,321	4,167	27.2%	11,154	72.8%
		4	1,247	15,317	3,872	25.3%	11,445	74.7%
		Total	4,522	45,971	12,200	26.5%	33,771	73.5%
	Total		17,269	135,614	101,843	75.1%	33,771	24.9%
2011/2012	1A	0	12,654	64,160	64,160	100.0%	0	0.0%
	1B	1	7,660	27,325	22,208	81.3%	5,117	18.7%
	2	2	3,498	20,321	3,072	15.1%	17,249	84.9%
		3	2,593	18,538	6,653	35.9%	11,885	64.1%
		4	2,080	18,194	6,383	35.1%	11,811	64.9%
		Total	8,171	57,053	16,108	28.2%	40,945	71.8%
	Total		28,485	148,538	102,476	69.0%	46,062	31.0%

Table 8-25 Table 8-25 ARR volume for ATSI Control Zone: 2011 to 2012 planning period[7] (New Table)

Planning Period	Bid and Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2011/2012	1,309	5,434	2,770	51%	2,663	49%

Table 8-26 Direct allocation of FTR volume for ATSI Control Zone: 2011 to 2012 planning period[8] (New Table)

Planning Period	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2011/2012	114	7,750	4,189	54%	3,561	46%

7 The 2011 to 2012 ARR volume data in Table 8-25 are included in the 2011 to 2012 ARR allocation data in Table 8-24.
8 The 2011 to 2012 directly allocated FTR volume data in Table 8-26 are not included in ARR allocation data in Table 8-24.

Revenue Adequacy

Table 8-27 ARR revenue adequacy (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012[9] (See 2010 SOM, Table 8-30)

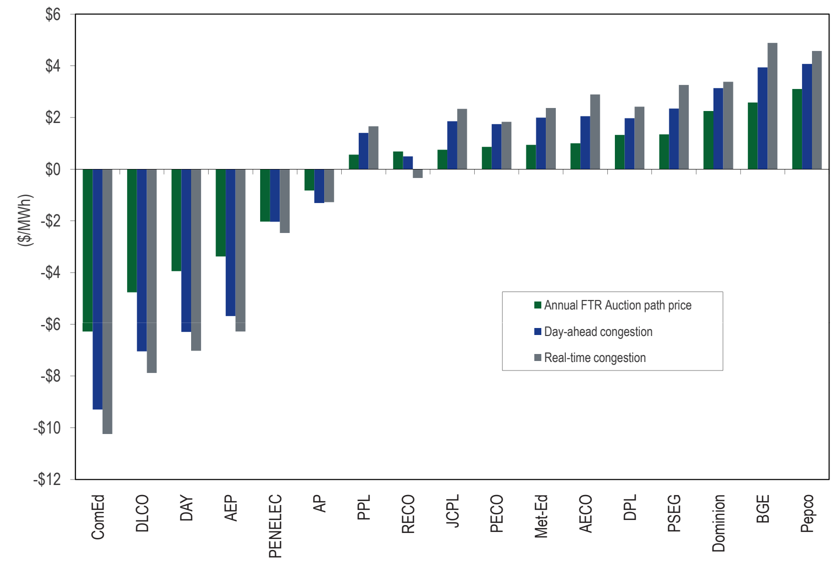
	2010/2011	2011/2012
Total FTR auction net revenue	$1,097.8	$1,070.8
Long Term FTR Auction net revenue	$23.5	$35.9
Annual FTR Auction net revenue	$1,049.8	$1,029.6
Monthly Balance of Planning Period FTR Auction net revenue*	$24.5	$5.3
ARR target allocations	$1,029.3	$982.9
ARR credits	$1,029.3	$982.9
Surplus auction revenue	$68.5	$87.9
ARR payout ratio	100%	100%
FTR payout ratio*	84.9%	86.9%

* Shows twelve months for 2010/2011 and one month ended 30-Jun-11 for 2011/2012

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

Figure 8-9 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2010 to 2011 (See 2010 SOM, Figure 8-12)



9 Table 8-26 has been updated from prior *State of the Market Reports* to include the net revenue for applicable FTRs from the Long Term FTR Auctions.

Effectiveness of ARRs as a Hedge against Congestion

Table 8-28 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2010 to 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	$5,622,487	$1,341,364	$6,963,851	$46,138,832	($39,174,981)	15.1%
AEP	$8,853,266	$158,320,173	$167,173,439	$215,795,577	($48,622,138)	77.5%
AP	$35,547,112	$309,221,148	$344,768,260	$96,780,725	$247,987,535	>100%
BGE	$29,986,713	$4,693,417	$34,680,130	$51,601,965	($16,921,835)	67.2%
ComEd	$82,312,055	$11,644,724	$93,956,779	($273,848,870)	$367,805,649	>100%
DAY	$3,657,086	$2,455,028	$6,112,114	$12,437,782	($6,325,668)	49.1%
DLCO	$5,052,309	$0	$5,052,309	$40,366,159	($35,313,850)	12.5%
Dominion	$4,991,988	$218,206,431	$223,198,419	$18,203,016	$204,995,403	>100%
DPL	$11,862,147	$1,708,372	$13,570,519	$68,190,323	($54,619,804)	19.9%
JCPL	$15,966,799	$3,571,964	$19,538,763	$72,165,600	($52,626,838)	27.1%
Met-Ed	$13,272,652	$838,299	$14,110,951	$31,052,881	($16,941,930)	45.4%
PECO	$1,707,188	$41,262,780	$42,969,968	($42,254,021)	$85,223,989	>100%
PENELEC	$23,696,177	$15,535	$23,711,712	$62,766,815	($39,055,103)	37.8%
Pepco	$20,673,905	$2,124,638	$22,798,543	$169,027,354	($146,228,811)	13.5%
PJM	$17,922,362	$3,843,243	$21,765,605	$23,849,999	($2,084,394)	91.3%
PPL	$20,247,335	$6,019,379	$26,266,714	$72,380,143	($46,113,429)	36.3%
PSEG	$38,443,990	$8,893,085	$47,337,075	($539,242)	$47,876,317	>100%
RECO	$93,249	$0	$93,249	$2,635,744	($2,542,495)	3.5%
Total	$339,908,820	$774,159,581	$1,114,068,401	$666,750,782	$447,317,619	>100%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-29 ARR and FTR congestion hedging by control zone: Planning period 2010 to 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	$6,095,482	$15,369,427	$8,369,233	$13,095,676	$34,133,780	($21,038,104)	38.4%
AEP	$194,446,396	$194,755,239	$191,918,504	$197,283,131	$167,295,357	$29,987,774	>100%
AP	$308,392,416	$323,835,972	$266,825,862	$365,402,526	$273,351,660	$92,050,866	>100%
BGE	$33,678,997	$76,134,111	$47,988,958	$61,824,150	$84,392,555	($22,568,405)	73.3%
ComEd	$91,566,097	$104,136,386	$81,016,392	$114,686,091	$266,568,467	($151,882,376)	43.0%
DAY	$5,788,157	$2,230,724	$1,857,507	$6,161,374	$5,375,791	$785,583	>100%
DLCO	$5,052,309	$4,346,220	($4,464,852)	$13,863,381	$22,358,730	($8,495,349)	62.0%
Dominion	$176,257,284	$255,520,037	$183,744,233	$248,033,088	$272,614,395	($24,581,307)	91.0%
DPL	$12,954,039	$28,026,874	$21,098,243	$19,882,670	$53,869,497	($33,986,827)	36.9%
JCPL	$18,916,958	$50,117,839	$22,815,912	$46,218,885	$63,092,857	($16,873,972)	73.3%
Met-Ed	$13,935,697	$18,999,152	$8,123,142	$24,811,707	$3,280,705	$21,531,002	>100%
PECO	$23,365,352	$62,435,534	$30,955,754	$54,845,132	($4,700,458)	$59,545,590	>100%
PENELEC	$23,704,470	$61,092,943	$30,722,601	$54,074,812	$91,243,496	($37,168,684)	59.3%
Pepco	$22,895,504	$126,441,016	$124,122,872	$25,213,648	$92,418,233	($67,204,585)	27.3%
PJM	$22,409,320	($4,729,082)	($7,470,423)	$25,150,661	($15,392,423)	$40,543,084	>100%
PPL	$27,383,200	$29,872,099	$17,810,715	$39,444,584	$1,334,287	$38,110,297	>100%
PSEG	$44,042,817	$86,747,606	$73,682,375	$57,108,048	($4,826,603)	$61,934,651	>100%
RECO	$93,249	($2,243,107)	($1,299,731)	($850,127)	$3,487,598	($4,337,725)	0.0%
Total	$1,030,977,744	$1,433,088,991	$1,097,817,297	$1,366,249,438	$1,409,897,924	($43,648,486)	96.9%

Table 8-30 ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011[10] (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
2009/2010	$1,274,578,024	$879,837,129	$1,368,743,667	$785,671,486	$816,996,460	($31,324,974)	96.2%
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%

ARRs and FTRs as a Hedge against Total Real Time Energy Charges

Table 8-31 ARRs and FTRs as a hedge against energy charges by control zone: January through June 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	$3,560,203	$3,092,518	$6,652,720	$287,023,900	2.3%
AEP	$78,607,670	$29,208,781	$107,816,451	$2,780,998,492	3.9%
AP	$117,215,427	$10,543,295	$127,758,722	$1,118,482,832	11.4%
ATSI	$1,024,101	$2,336,756	$3,360,857	$259,636,298	1.3%
BGE	$17,177,996	($6,182,300)	$10,995,696	$936,666,014	1.2%
ComEd	$48,751,974	$7,364,004	$56,115,978	$1,761,949,470	3.2%
DAY	$2,667,065	$262,715	$2,929,780	$346,233,992	0.8%
DLCO	$2,381,157	$1,774,089	$4,155,247	$300,163,013	1.4%
Dominion	$75,718,693	$8,012,216	$83,730,909	$2,533,143,836	3.3%
DPL	$6,472,997	($1,152,860)	$5,320,137	$502,331,377	1.1%
JCPL	$8,611,894	$10,764,043	$19,375,937	$625,710,190	3.1%
Met-Ed	$6,935,438	($451,950)	$6,483,488	$398,440,111	1.6%
PECO	$22,832,202	$6,535,357	$29,367,559	$1,087,458,820	2.7%
PENELEC	$11,801,550	$2,698,715	$14,500,265	$412,323,528	3.5%
Pepco	$13,833,821	($10,978,016)	$2,855,805	$874,301,061	0.3%
PJM	$9,933,241	$234,915	$10,168,155	NA	NA
PPL	$11,127,993	$16,037,077	$27,165,071	$1,101,844,442	2.5%
PSEG	$25,061,875	$4,832,808	$29,894,684	$1,204,709,540	2.5%
RECO	($13,676)	($613,717)	($627,393)	$36,599,726	(1.7%)
Total	$463,701,621	$84,318,448	$548,020,069	$16,592,328,459	3.3%

10 The FTR credits do not include after-the-fact adjustments. For the 2010 to 2011 planning period, the ARR credits were the total credits allocated to all ARR holders for the full twelve months (June 2010 through May 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 full twelve months of this planning period and the portion of Annual FTR Auction revenue distributed during those twelve months.