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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 *2010 Quarterly State of the Market Report for PJM: January through June*.

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § IV.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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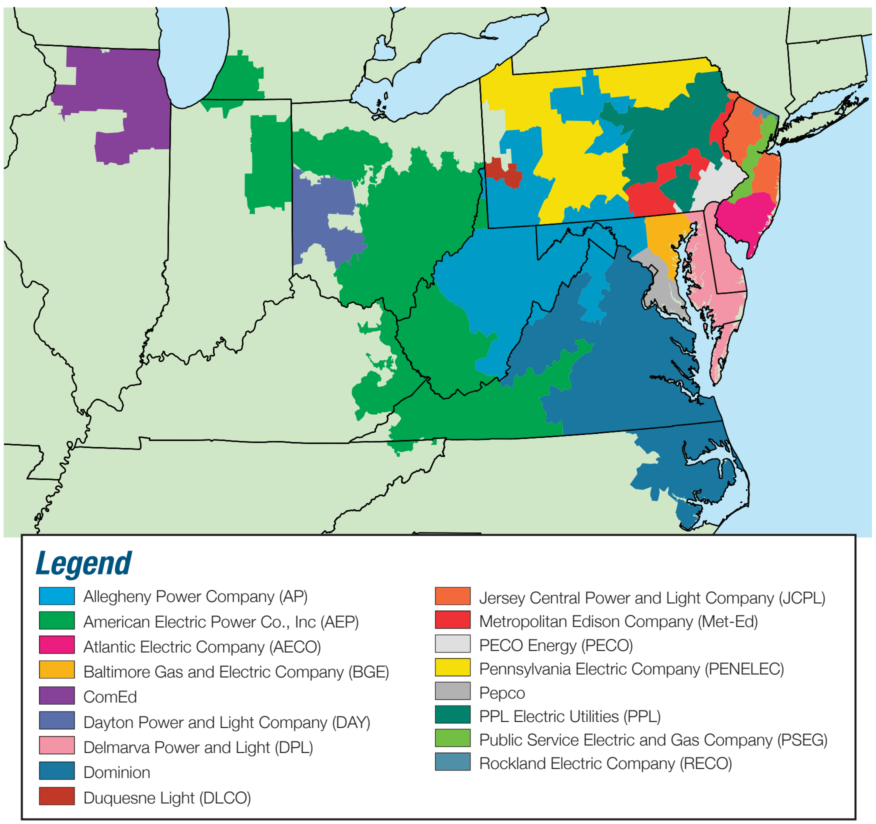
SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of June 30, 2010, had installed generating capacity of 166,622 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 51 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. (See Figure 1-1.)[1] As part of that 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 17 control zones (See 2009 SOM, Figure A-1)



1 See the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

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 in mid-1999. 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.[2, 3]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first six months of 2010, 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.

2 See also the *2009 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

3 Analysis of 2010 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. 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, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

The MMU concludes that in the first six months of 2010:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;
- The Regulation Market results were not competitive;[4]
- The Synchronized Reserve Market results were competitive;
- The Day Ahead Scheduling Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

Role of MMU in Market Design Recommendations

The PJM Market Monitoring Plan provides under the heading "Market Design," in the section setting forth the MMU's function and responsibilities:

> PJM is responsible for proposing for approval by the Commission, consistent with tariff procedures and applicable law, changes to the design of the PJM Markets. If the Market Monitoring Unit detects a design flaw or other problem with the PJM Markets, the Market Monitoring Unit may initiate and propose, through the appropriate stakeholder processes, changes to the design of such market. In support of this function, the Market Monitoring Unit may engage in discussions with stakeholders, State Commissions, PJM Management, or the PJM Board; participate in PJM stakeholder meetings or working groups regarding market design matters; publish proposals, reports or studies on such market design issues; and make filings with the Commission on market design issues.[5]

In addition, the PJM Market Monitoring Plan provides, in describing MMU Reports: "In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview."[6]

Recommendations

The MMU recommends retention of key market rules, specific enhancements to those 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 *2010 Quarterly State of the Market Report for PJM: January through June*, the recommendations from the *2009 State of the Market Report for PJM* and the *2010 Quarterly State of the Market Report for PJM: January through March* are still valid, and the MMU has no new recommendations for the first six months of 2010.

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, transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-1 provides the average price and total revenues paid, by component for calendar year 2009 and for January through June 2010. 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 in the first six months of 2010.
- 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.[7]

4 The regulation market results are not the result of the offer behavior of market participants, which is 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, 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 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 opportunity cost than its owner does.

5 PJM OATT Attachment M § IV.D. On March 18, 2010, PJM filed in Docket No. ER09-1063-003 revisions to Attachment M that, among other things, describe the full scope of this core function, consistent with the Commission's order of December 18, 2009 on PJM's initial filing in compliance with Order No. 719. 125 FERC ¶61,250 at P 113.

6 PJM OATT Attachment M § VI.A.

7 PJM OATT Section 13.7, Section 14.5 & 27A and Section 34.

- The Operating Reserve (Uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[8]

- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[9]

- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[10]

- 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 TrAILCo and PATH projects.[11]

- 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.[12]

- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[13]

- The Black Start component is the average cost per MWh of black start service.[14]

- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[15]

- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[16]

- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[17]

- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[18]

Table 1-1 Total price per MWh by Category and Total Revenues by Category: January through December 2009 and January through June 2010 (See 2009 SOM, Table 1-1)

Category	Totals ($ Millions) Jan-Dec 2009	Totals ($ Millions) Jan-Jun 2010	Jan-Dec 2009 $/MWh	Jan-Jun 2010 $/MWh	Jan-Dec 2009 Percent	Jan-Jun 2010 Percent
Energy	$26,008.22	$15,518.26	$39.05	$45.75	70.2%	71.9%
Capacity	$7,162.71	$3,966.86	$10.75	$11.69	19.3%	18.4%
Transmission Service Charges	$2,664.73	$1,359.44	$4.00	$4.01	7.2%	6.3%
Operating Reserves (Uplift)	$324.15	$244.18	$0.49	$0.72	0.9%	1.1%
PJM Administrative Fees	$242.32	$125.33	$0.36	$0.37	0.7%	0.6%
Reactive	$228.18	$124.67	$0.34	$0.37	0.6%	0.6%
Regulation	$203.49	$116.30	$0.31	$0.34	0.5%	0.5%
Transmission Enhancement Cost Recovery	$63.21	$48.88	$0.09	$0.14	0.2%	0.2%
Transmssion Owner (Schedule 1A)	$56.47	$29.01	$0.08	$0.09	0.2%	0.1%
Synchronized Reserves	$34.27	$18.87	$0.05	$0.06	0.1%	0.1%
NERC/RFC	$8.86	$6.83	$0.01	$0.02	0.0%	0.0%
Black Start	$14.27	$5.36	$0.02	$0.02	0.0%	0.0%
RTO Startup and Expansion	$9.12	$4.55	$0.01	$0.01	0.0%	0.0%
Load Response	$1.62	$2.13	$0.00	$0.01	0.0%	0.0%
Transmission Facility Charges	$1.39	$0.67	$0.00	$0.00	0.0%	0.0%
Total	$37,023.01	$21,571.34	$55.58	$63.59	100.0%	100.0%

8 PJM Operating Agreement Schedules 1-3.2.3 & 1-3.3.3.
9 PJM OATT Schedule 2 and Operating Agreement Schedule 1-3.2.3B.
10 PJM Operating Agreement Schedules 1-3.2.2, 1-3.2.2A, 1-3.3.2, 1-3.3.2A and OATT Schedule 3.
11 PJM OATT Schedule 12.
12 PJM OATT Schedule 1A.
13 PJM Operating Agreement Schedule 1-3.2.3A.01 and OATT Schedule 6.
14 PJM OATT Schedule 6A.
15 PJM OATT Attachments H-13, H-14 and H-15 and Schedule 13.
16 PJM OATT Schedule 10-NERC and OATT Schedule 10-RFC.
17 PJM Operating Agreement Schedule 1-3.6.
18 PJM Operating Agreement Schedule 1-3.6.

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 2010, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2010.

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.

1 Analysis of 2010 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. 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 *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

2 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," First Revised Sheet No. 448.05 (Effective June 29, 2009).

Overview

Market Structure

- **Supply.** During the second quarter of 2010, the PJM Energy Market received an hourly average of 155,015 MW in supply offers including hydroelectric generation.[3] The second quarter 2010 average daily offered supply was 646 MW higher than the second quarter 2009 average daily offered supply of 154,369 MW.

- **Demand.** The PJM system peak load for the second quarter 2010 was 126,188 MW in the hour ended 1700 EPT on June 23, 2010, while the PJM peak load for the second quarter 2009 was 116,751 MW in the hour ended 1700 EPT on June 25, 2009.[4] The second quarter 2010 peak load was 9,437 MW, or 8.1 percent, higher than the second quarter 2009 peak load.

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

- **Local Market Structure and Offer Capping.** 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 pivotal supplier test) as the trigger for offer capping in 2010. PJM offer caps units only when the local market structure is noncompetitive. Offer

3 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.

4 For the purpose of the *2010 Quarterly State of the Market Report for PJM: January through June*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2009 State of the Market Report for PJM*, Appendix N, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.1 percent in 2009 to 0.3 percent in the first six months of 2010. In the Real-Time Energy Market offer-capped unit hours increased from 0.4 percent in 2009 to 1.0 percent in the period from January through June 2010.

As of 9:30 AM on June 9, 2010, PJM replaced LA UDS with new short run look ahead Security Constrained Economic Dispatch (SCED; SCED 2; or IT SCED) optimization software. The three pivotal supplier test (TPS) is now run in SCED. Each pass of the SCED 2 software produces multiple security constrained optimization and unit commitment results for anticipated system conditions fifteen to one hundred and twenty minutes into the future. Generally, there is a SCED 2 pass every 15 minutes. The TPS test is calculated for any constraints that require incremental relief in each of the forward market solutions generated by each pass of the SCED 2 software. For example, this means that a SCED 2 pass that produces results for 15, 30, 45 and 120 minutes in the future will have four complete sets of TPS results, one set for each forward market solution. Each pass of the LA UDS produced only one set of TPS results.

- **Local Market Structure.** For the period January 1, 2010, through June 8, 2010, a summary of the TPS results based on the LA UDS is presented for all constraints which occurred for 50 or more hours during the first six months of calendar year 2010. For the period June 9, 2010 (9:30 AM), through June 30, 2010, a summary of the TPS results based on SCED is presented for all regional 500 kV constraints.

  During the first six months of 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, 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 three pivotal supplier test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, as such a full redispatch is practically impossible because it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

  The markup component of the overall PJM real-time, load-weighted, average LMP for the first six months of 2010 was -$1.15 per MWh, or -2.5 percent. Coal steam units contributed -$1.74, or 151.9 percent, to the total markup component of LMP. Combustion turbine units that use natural gas as their primary fuel source contributed $0.22 or -19.5 percent to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.29 or -25.7 percent to the total markup component of LMP. The markup was -$0.59 per MWh during peak hours and -$1.73 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP for the first six months of 2010 was -$1.12 per MWh, or -2.4 percent. Coal steam units contributed -$0.97 or 87.0 percent to the total markup component of LMP. Natural gas steam units contributed -$0.14 or 12.4 percent to the total markup component of LMP. The markup was -$0.65 per MWh during peak hours and -$1.61 per MWh during off-peak hours.

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

- **Load.** On average, PJM real-time load increased in the first six months of 2010 by 2.8 percent from the first six months of 2009, rising from 75,993 MW to 78,106 MW. PJM day-ahead load increased in the first six months of 2010 by 1.3 percent from the first six months of 2009, rising from 88,688 MW to 89,830 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 and local price differences caused by congestion.

  PJM Real-Time Energy Market prices increased in the first six months of 2010 compared to the first six months of 2009. The system simple average LMP was 7.9 percent higher in the first six months of 2010 than in the first six months of 2009, $43.27 per MWh versus $40.12 per MWh. The load-weighted LMP was 7.7 percent higher in the first six months of 2010 than the first six months of 2009, $45.75 per MWh versus $42.48 per MWh. The real-time, fuel cost adjusted, load-weighted, average LMP was 17.3 percent higher for the first six months of 2010 than the load-weighted, average LMP for the first six months of 2009, $49.81 per MWh versus $42.48 per MWh. In other words, if fuel costs in the first six months of 2010 were the same as they had been in the first six months of 2009, the 2010 load-weighted LMP would have been higher, $49.81 per MWh, than the actual $45.75 per MWh, and 17.3 percent higher than the load-weighted average LMP for the first six months of 2009. Higher loads contributed to upward pressure on LMP while fuel costs contributed to downward pressure on LMP in the first half of 2010.

  PJM Day-Ahead Energy Market prices increased in the first six months of 2010 compared to the first six months of 2009. The system simple average LMP was 9.5 percent higher in the first six months of 2010 than in the first six months of 2009, $43.81 per MWh versus $40.01 per MWh. The load-weighted LMP was 9.3 percent higher in the first six months of 2010 than in the first six months of 2009, $46.12 per MWh versus $42.21 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 PJM parent company 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 2010, 12.0 percent of real-time load was supplied by bilateral contracts, 18.6 percent by spot market purchases and 69.4 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 0.8 percentage points; reliance on spot supply increased by 1.6 percentage points; and reliance on self-supply decreased by 0.7 percentage points in 2010.

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 an RTO Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior.

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

- **Demand-Side Response Activity.** In the first six months of 2010, in the Economic Program, participation decreased compared to the first six months of 2009. There were decreases in a range of activity metrics including settlements submitted, settled MWh and credits. Participation levels through calendar year 2009 and through the first six months of 2010 are generally 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 2010 (June 23, 2010), there were 1,891.5 MW registered in the Economic Load Response Program.

In the first six months of 2010, the Emergency Program, specifically, the Load Management (LM) Program, participation increased compared to the same period in 2009.[5] Participants in the LM Program are committed resources that receive RPM capacity credits and participation continues to increase through RPM delivery years. For the 2010/2011 delivery year, there were 9,052.4 MW registered in the LM Program, compared to 7,294.3 MW registered in the 2009/2010 delivery year.

Since the introduction of the RPM capacity market on June 1, 2007 the capacity market has been the source of growth in total demand side revenues and demand side revenues from the capacity market were the only significant source of revenue in 2009 and through the first six months of 2010. In the first six months of 2010, payments from the Economic Program decreased from the first six months of 2009 by $410,000 or 48 percent, from $853,000 to $443,000 while capacity revenue increased from the first six months of 2009 by $101 million or 89 percent, from $114 million to $214 million since 2009.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the first six months of 2010, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply increased by about 646 MW when comparing the second quarter of 2010 to the second quarter of 2009, while aggregate peak load increased by 9,437 MW, modifying the general supply demand balance from the second quarter of 2009 with a corresponding impact on Energy Market prices. Average load in the first six months of 2010 also increased from the first six months of 2009. Market concentration levels remained moderate and average markup was negative. 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.

5 The Capacity Only and Full options of the Emergency Program are integrated into RPM through the Load Management Program. The Energy Only option is a voluntary program that does not interact with RPM, however, there are currently no participants registered in this option.

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 scarcity conditions. 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.

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, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. 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.

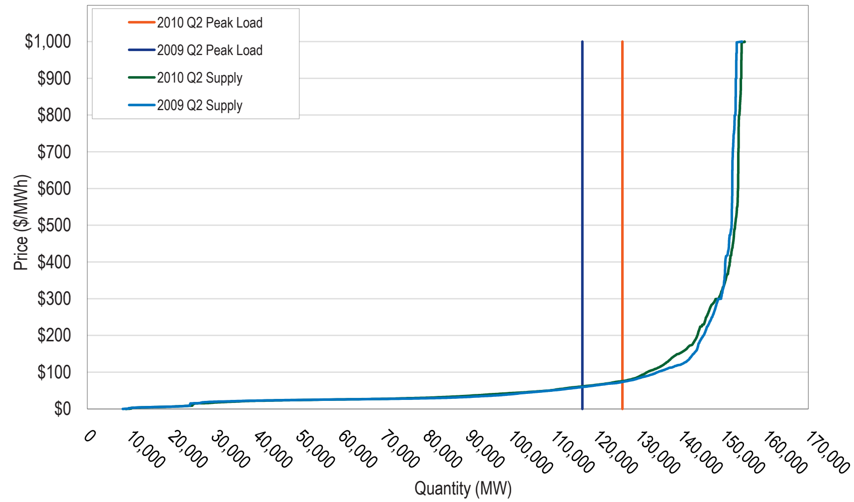
Energy Market results for the first six months of 2010 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher demand, mitigated by lower fuel costs. PJM Real-Time, load-weighted, average LMP for the first six months of 2010 was $45.75, or 7.7 percent higher than the load-weighted, average LMP for the first six months of 2009, which was $42.48. The real-time fuel cost adjusted, load-weighted, average LMP was 17.3 percent higher for the first six months of 2010 than the load-weighted, average LMP in for the first six months of 2009, $49.81 per MWh compared to $42.48 per MWh. In other words, if fuel costs in the first six months of 2010 were the same as they had been in the first six months of 2009, the 2010 load-weighted LMP would have been higher, $49.81 per MWh, than the actual $45.75 per MWh, and 17.3 percent higher than the load-weighted average LMP for the first six months of 2009. Higher loads contributed to upward pressure on LMP while fuel costs contributed to downward pressure on LMP in the first half of 2010.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2010.

Market Structure

Supply

Figure 2-1 Average PJM aggregate supply curves: April through June, 2009 and 2010 (See 2009 SOM, Figure 2-1)



Demand

Table 2-1 Actual PJM footprint peak loads: April through June of 2003 to 2010 (See 2009 SOM, Table 2-1)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)	Difference (%)
2003	Wed, June 25	17	61,310	NA	NA
2004	Wed, June 09	17	77,676	16,366	26.7%
2005	Tue, June 28	16	124,052	46,375	59.7%
2006	Tue, May 30	17	121,165	(2,887)	(2.3%)
2007	Wed, June 27	16	130,971	9,806	8.1%
2008	Mon, June 09	17	130,100	(871)	(0.7%)
2009	Thu, June 25	17	116,751	(13,349)	(10.3%)
2010	Wed, June 23	17	126,188	9,438	8.1%

Figure 2-2 Actual PJM footprint peak loads: April through June of 2003 to 2010 (See 2009 SOM, Figure 2-2)

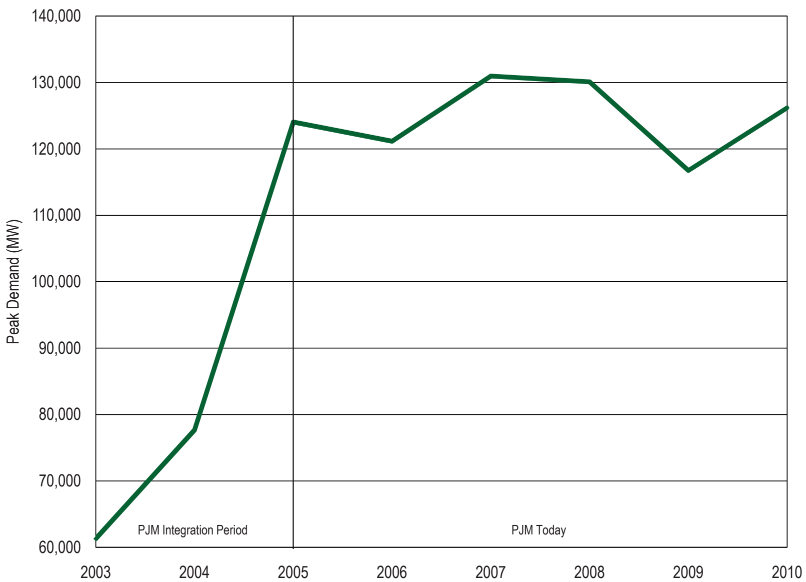
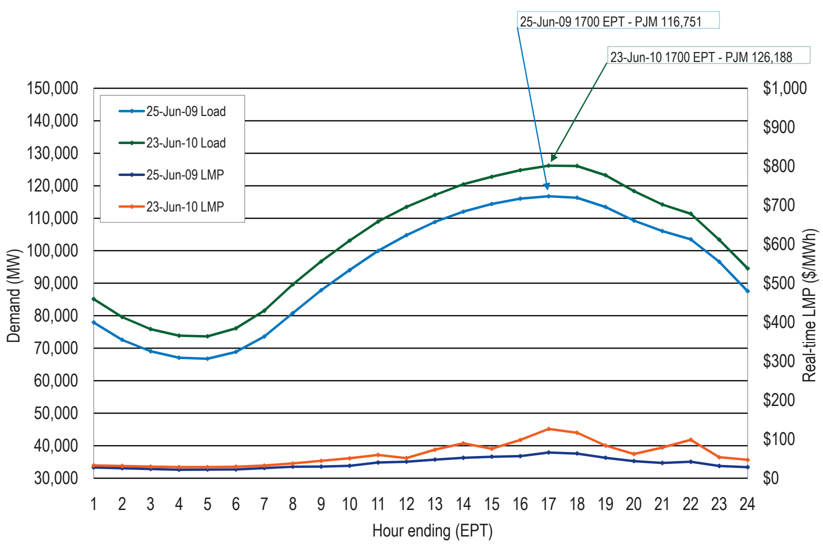


Figure 2-3 PJM second quarter peak-load comparison: Wednesday, June 23, 2010 and Thursday, June 25, 2009 (See 2009 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

Table 2-2 PJM hourly Energy Market HHI: January through June 2010[6] (See 2009 SOM, Table 2-2)

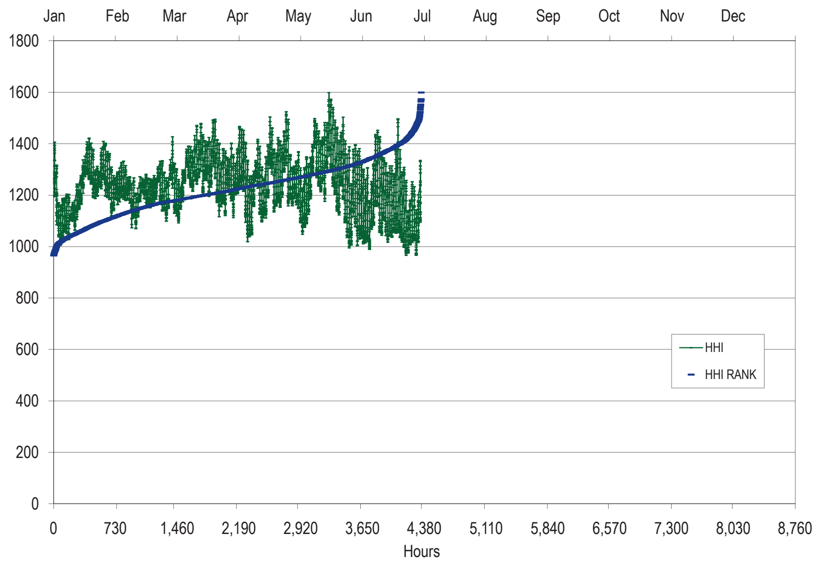
	Hourly Market HHI
Average	1222
Minimum	966
Maximum	1599
Highest market share (One hour)	31%
Highest market share (All hours)	21%
# Hours	4,343
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Table 2-3 PJM hourly Energy Market HHI (By segment): January through June 2010 (See 2009 SOM, Table 2-3)

	Minimum	Average	Maximum
Base	1125	1273	1567
Intermediate	689	1898	9079
Peak	728	5878	10000

6 This analysis includes all hours of the first six months of 2010, regardless of congestion.

Figure 2-4 PJM hourly Energy Market HHI: January through June 2010 (See 2009 SOM, Figure 2-4)



Local Market Structure and Offer Capping

Table 2-4 Annual real-time offer-capping statistics: Calendar years 2006 through June 2010 (See 2009 SOM, Table 2-4)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2006	1.0%	0.2%	0.4%	0.1%
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	1.0%	0.3%	0.3%	0.1%

Table 2-5 Real-time offer-capped unit statistics: January through June 2010 (See 2009 SOM, Table 2-5)

	2010 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	1	1	0	1	1	57
80% and < 90%	0	0	0	0	1	27
75% and < 80%	2	0	0	0	0	6
70% and < 75%	0	0	0	0	1	3
60% and < 70%	0	0	0	0	3	19
50% and < 60%	0	0	0	0	2	28
25% and < 50%	1	0	0	2	2	47
10% and < 25%	0	1	1	1	2	39

Local Market Structure[7]

Table 2-6 Look ahead UDS based three pivotal supplier results summary for regional constraints: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-6)

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	720	625	87%	180	25%
	Off Peak	465	408	88%	114	25%
AP South	Peak	2,106	1,102	52%	1,462	69%
	Off Peak	1,734	949	55%	1,132	65%
Bedington - Black Oak	Peak	167	138	83%	48	29%
	Off Peak	34	17	50%	23	68%
Central	Peak	6	6	100%	0	0%
	Off Peak	NA	NA	NA	NA	NA
Harrison - Pruntytown	Peak	116	105	91%	25	22%
	Off Peak	281	204	73%	136	48%
West	Peak	114	108	95%	9	8%
	Off Peak	43	37	86%	8	19%

Table 2-7 SCED 2 based three pivotal supplier results summary for regional constraints: June 9, 2010 through June 30, 2010 (See 2009 SOM, Table 2-6)

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	553	10	2%	548	99%
	Off Peak	28	2	7%	27	96%
AP South	Peak	2,764	26	1%	2,758	100%
	Off Peak	1,474	18	1%	1,471	100%
Harrison - Pruntytown	Peak	55	0	0%	55	100%
	Off Peak	NA	NA	NA	NA	NA

7 Effective June 9, 2010, at 9:30 AM, the three pivotal supplier test (TPS) was run in PJM's new short run look ahead Security Constrained Economic Dispatch (SCED) optimization software instead of the Look-Ahead Unit Dispatch Software (LA UDS). For the period January 1, 2010, through June 8, 2010, the MMU is reporting all LA UDS based TPS results for all the transmission constraints with 50 or more constrained hours For the period June 9, 2010, starting at 9:30 am, through June 30, 2010, the MMU is reporting SCED 2 based TPS results for regional 500 kv constraints.

Table 2-8 Look ahead UDS based three pivotal supplier test details for regional constraints: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-7)

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	76	279	19	16	3
	Off Peak	58	260	18	16	3
AP South	Peak	76	234	11	5	6
	Off Peak	73	243	10	5	5
Bedington - Black Oak	Peak	48	158	16	13	3
	Off Peak	102	187	14	5	9
Central	Peak	139	1,333	21	21	0
	Off Peak	NA	NA	NA	NA	NA
Harrison - Pruntytown	Peak	64	308	20	17	2
	Off Peak	63	210	17	11	5
West	Peak	125	712	19	17	1
	Off Peak	111	640	22	19	3

Table 2-9 SCED 2 based three pivotal supplier test details for regional constraints: June 8, 2010 through June 30, 2010 (See 2009 SOM, Table 2-7)

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	545	2,069	17	0	17
	Off Peak	416	1,512	13	1	13
AP South	Peak	391	946	8	0	8
	Off Peak	476	1,103	8	0	8
Harrison - Pruntytown	Peak	252	551	8	0	8
	Off Peak	NA	NA	NA	NA	NA

Table 2-10 Three pivotal supplier results summary for constraints located in the AECO Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-10)

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
England - Middletap	Peak	52	0	0%	52	100%
	Off Peak	106	0	0%	106	100%

Table 2-11 Three pivotal supplier test details for constraints located in the AECO Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-11)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
England - Middletap	Peak	3	33	2	0	2
	Off Peak	4	35	2	0	2

Table 2-12 Three pivotal supplier results summary for constraints located in the AEP Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-12)

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
Baker - Broadford	Peak	62	17	27%	48	77%
	Off Peak	276	140	51%	210	76%
Cloverdale - Lexington	Peak	152	89	59%	87	57%
	Off Peak	1,021	473	46%	740	72%
Conesville - Prep Plant Tap	Peak	271	0	0%	271	100%
	Off Peak	8	0	0%	8	100%
Mahans Lane - Tidd	Peak	158	0	0%	158	100%
	Off Peak	13	0	0%	13	100%

Table 2-13 Three pivotal supplier test details for constraints located in the AEP Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-13)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Baker - Broadford	Peak	40	124	9	2	7
	Off Peak	66	215	9	4	6
Cloverdale - Lexington	Peak	78	211	17	10	7
	Off Peak	75	163	14	5	9
Conesville - Prep Plant Tap	Peak	12	35	2	0	2
	Off Peak	10	46	2	0	2
Mahans Lane - Tidd	Peak	8	11	1	0	1
	Off Peak	3	9	2	0	2

Table 2-14 Three pivotal supplier results summary for constraints located in the AP Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-14)

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
Albright - Mt. Zion	Peak	185	0	0%	185	100%
	Off Peak	254	0	0%	254	100%
Doubs	Peak	834	255	31%	652	78%
	Off Peak	163	40	25%	144	88%
Middlebourne - Willow	Peak	208	0	0%	208	100%
	Off Peak	223	0	0%	223	100%
Mount Storm - Pruntytown	Peak	18	18	100%	3	17%
	Off Peak	291	157	54%	179	62%
Tiltonsville - Windsor	Peak	937	0	0%	937	100%
	Off Peak	627	0	0%	627	100%
Wylie Ridge	Peak	NA	NA	NA	NA	NA
	Off Peak	178	152	85%	57	32%

Table 2-15 Three pivotal supplier test details for constraints located in the AP Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-15)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Albright - Mt. Zion	Peak	8	5	1	0	1
	Off Peak	14	6	1	0	1
Doubs	Peak	22	38	8	4	4
	Off Peak	19	46	8	2	6
Middlebourne - Willow	Peak	9	2	1	0	1
	Off Peak	11	2	1	0	1
Mount Storm - Pruntytown	Peak	27	265	9	8	1
	Off Peak	81	239	10	6	5
Tiltonsville - Windsor	Peak	9	4	2	0	2
	Off Peak	10	5	2	0	2
Wylie Ridge	Peak	NA	NA	NA	NA	NA
	Off Peak	29	125	16	13	3

Table 2-16 Three pivotal supplier results summary for constraints located in the BGE Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-16)

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
Brandon Shores - Riverside	Peak	168	138	82%	66	39%
	Off Peak	4	4	100%	2	50%
Graceton - Raphael Road	Peak	232	170	73%	108	47%
	Off Peak	47	38	81%	23	49%

Table 2-17 Three pivotal supplier test details for constraints located in the BGE Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-17)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brandon Shores - Riverside	Peak	21	112	16	13	3
	Off Peak	25	88	19	18	2
Graceton - Raphael Road	Peak	43	122	18	13	6
	Off Peak	49	142	17	12	5

Table 2-18 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-18)

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
Burnham - Munster	Peak	31	21	68%	10	32%
	Off Peak	406	123	30%	320	79%
East Frankfort - Crete	Peak	187	17	9%	178	95%
	Off Peak	3,520	66	2%	3,489	99%
Electric Jct - Nelson	Peak	49	0	0%	49	100%
	Off Peak	111	0	0%	111	100%
Pleasant Valley - Belvidere	Peak	348	0	0%	348	100%
	Off Peak	489	0	0%	489	100%
Waterman - West Dekalb	Peak	264	0	0%	264	100%
	Off Peak	446	0	0%	446	100%
Wilton Center	Peak	45	27	60%	19	42%
	Off Peak	505	53	10%	475	94%
Zion - Pleasant Prairie	Peak	266	0	0%	266	100%
	Off Peak	265	0	0%	265	100%

Table 2-19 Three pivotal supplier test details for constraints located in the ComEd Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-19)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Munster	Peak	25	97	22	15	6
	Off Peak	40	81	13	4	9
East Frankfort - Crete	Peak	33	116	6	1	5
	Off Peak	33	43	4	0	4
Electric Jct - Nelson	Peak	33	1	1	0	1
	Off Peak	28	3	2	0	2
Pleasant Valley - Belvidere	Peak	11	3	1	0	1
	Off Peak	11	1	1	0	1
Waterman - West Dekalb	Peak	9	0	1	0	1
	Off Peak	9	1	1	0	1
Wilton Center	Peak	27	108	17	13	4
	Off Peak	39	44	7	1	6
Zion - Pleasant Prairie	Peak	57	8	2	0	2
	Off Peak	55	6	2	0	2

Table 2-20 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-20)

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
Collier - Elwyn	Peak	533	0	0%	533	100%
	Off Peak	51	0	0%	51	100%
Crescent	Peak	757	0	0%	757	100%
	Off Peak	NA	NA	NA	NA	NA

Table 2-21 Three pivotal supplier test details for constraints located in the DLCO Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-21)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Collier - Elwyn	Peak	15	7	1	0	1
	Off Peak	15	9	1	0	1
Crescent	Peak	16	5	1	0	1
	Off Peak	NA	NA	NA	NA	NA

Table 2-22 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-22)

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
Beechwood - Kerr Dam	Peak	176	0	0%	176	100%
	Off Peak	150	0	0%	150	100%
Bremo - Kidds Store	Peak	275	0	0%	275	100%
	Off Peak	125	0	0%	125	100%
Clover	Peak	191	33	17%	183	96%
	Off Peak	6	0	0%	6	100%
Danville - East Danville	Peak	91	0	0%	91	100%
	Off Peak	218	1	0%	217	100%
Fredericksburg	Peak	139	0	0%	139	100%
	Off Peak	10	0	0%	10	100%
Pleasant View	Peak	276	199	72%	106	38%
	Off Peak	8	0	0%	8	100%

Table 2-23 Three pivotal supplier test details for constraints located in the Dominion Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-23)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	4	8	1	0	1
	Off Peak	4	3	1	0	1
Bremo - Kidds Store	Peak	7	19	1	0	1
	Off Peak	6	13	1	0	1
Clover	Peak	25	89	6	1	6
	Off Peak	8	43	5	0	5
Danville - East Danville	Peak	21	24	4	0	4
	Off Peak	16	14	3	0	3
Fredericksburg	Peak	8	82	1	0	1
	Off Peak	19	53	1	0	1
Pleasant View	Peak	46	118	19	14	5
	Off Peak	29	42	9	0	9

Table 2-24 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-30)

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
Athenia - Saddlebrook	Peak	1,169	1	0%	1,169	100%
	Off Peak	341	0	0%	341	100%
Branchburg - Readington	Peak	204	0	0%	204	100%
	Off Peak	3	0	0%	3	100%

Table 2-25 Three pivotal supplier test details for constraints located in the PSEG Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-31)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	12	40	2	0	2
	Off Peak	10	38	1	0	1
Branchburg - Readington	Peak	21	91	2	0	2
	Off Peak	10	95	3	0	3

Market Performance: Markup

Real-Time Markup

Ownership of Marginal Resources

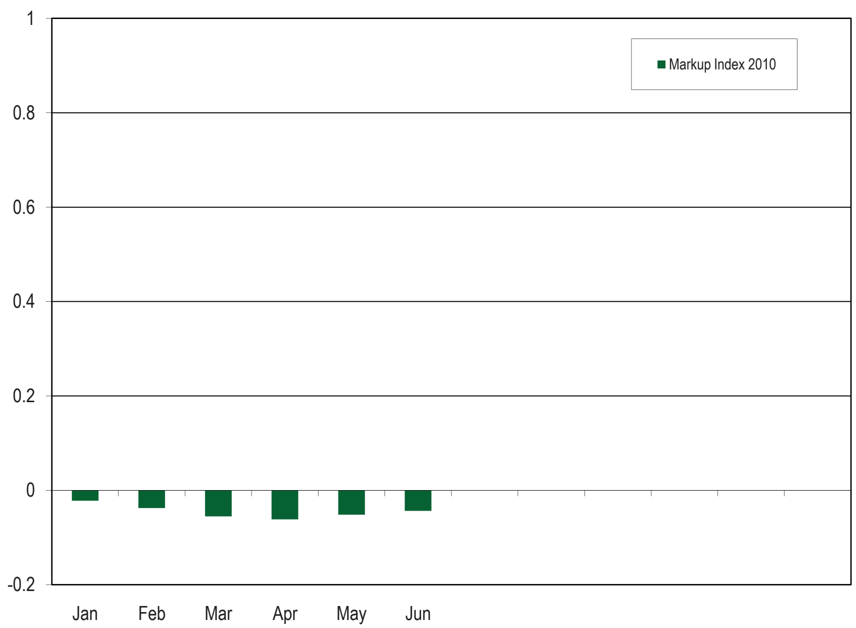
Table 2-26 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through June 2010 (See 2009 SOM, Table 2-32)

Company	Percent of Price
1	18%
2	14%
3	11%
4	6%
5	5%
6	5%
7	4%
8	3%
9	3%
Other (50 companies)	31%

Table 2-27 Type of fuel used (By real-time marginal units): January through June 2010 (See 2009 SOM, Table 2-33)

Fuel Type	2010
Coal	68%
Natural Gas	25%
Petroleum	3%
Wind	2%
Landfill Gas	1%
Misc	1%

Figure 2-5 Real-time load-weighted unit markup index: January through June 2010 (See 2009 SOM, Figure 2-5)



Unit Markup Characteristics

Table 2-28 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through June 2010 (See 2009 SOM, Table 2-34)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.74)	151.9%
Gas	CC	$0.29	(25.7%)
Gas	CT	$0.22	(19.5%)
Gas	Diesel	($0.00)	0.1%
Gas	Steam	($0.02)	1.6%
Interface	Interface	($0.00)	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.01	(1.2%)
Oil	CT	$0.01	(1.2%)
Oil	Diesel	($0.01)	0.5%
Oil	Steam	$0.03	(3.0%)
Uranium	Steam	$0.00	(0.0%)
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.04	(3.5%)
Total		($1.15)	100.0%

Table 2-29 Average, real-time marginal unit markup index (By price category): January through June 2010 (See 2009 SOM, Table 2-35)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($3.21)
$25 to $50	(0.07)	($2.82)
$50 to $75	0.02	$1.26
$75 to $100	0.06	$4.61
$100 to $125	0.09	$9.29
$125 to $150	0.11	$14.37
> $150	0.05	$11.15

Markup Component of System Price

Table 2-30 Monthly markup components of real-time load-weighted LMP: January through June 2010 (See 2009 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.56	$0.00	$1.03
Feb	($1.53)	($1.19)	($1.88)
Mar	($2.01)	($1.38)	($2.73)
Apr	($2.36)	($2.52)	($2.17)
May	($2.93)	$0.50	($6.14)
Jun	$0.66	$0.75	$0.56
2010	($1.15)	($0.59)	($1.73)

Markup Component of Real-Time Zonal Prices

Table 2-31 Average real-time zonal markup component: January through June 2010 (See 2009 SOM, Table 2-37)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$0.23	$2.27	($1.86)
AEP	($3.56)	($4.47)	($2.63)
AP	($2.23)	($0.87)	($3.62)
BGE	$1.47	$4.49	($1.60)
ComEd	($1.38)	($3.16)	$0.55
DAY	($3.59)	($4.27)	($2.84)
DLCO	($2.28)	($1.59)	($3.02)
Dominion	$0.27	$2.06	($1.54)
DPL	$0.07	$1.47	($1.35)
JCPL	($0.12)	$1.90	($2.33)
Met-Ed	($0.30)	$1.17	($1.87)
PECO	($0.02)	$1.54	($1.65)
PENELEC	($1.68)	($1.41)	($1.96)
Pepco	$0.12	$1.79	($1.64)
PPL	($0.22)	$1.06	($1.58)
PSEG	($0.16)	$1.09	($1.54)
RECO	($0.58)	($0.10)	($1.13)

Markup by Real-Time System Price Levels

Table 2-32 Average real-time markup component (By price category): January through June 2010 (See 2009 SOM, Table 2-38)

	Average Markup Component	Frequency
Below $20	($2.97)	2.0%
$20 to $40	($3.42)	57.4%
$40 to $60	($0.80)	26.7%
$60 to $80	$6.16	7.8%
$80 to $100	($5.78)	3.1%
$100 to $120	$12.45	1.5%
$120 to $140	$15.48	0.9%
$140 to $160	$20.06	0.3%
Above $160	$25.96	0.3%

Day-Ahead Markup

Ownership of Marginal Resources

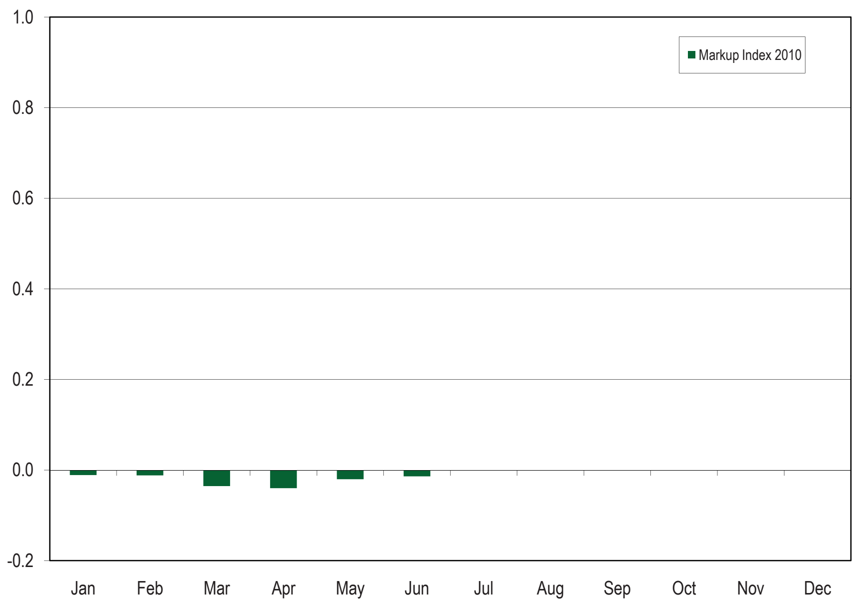
Table 2-33 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through June 2010 (See 2009 SOM, Table 2-39)

Company	Percent of Price
1	25%
2	8%
3	5%
4	5%
5	5%
6	5%
7	4%
8	3%
9	3%
Other (118 companies)	37%

Table 2-34 Day-ahead marginal resources by type/fuel: January through June 2010 (See 2009 SOM, Table 2-40)

Type/Fuel	2010
Transaction	33%
DEC	30%
INC	23%
Coal	10%
Natural gas	3%
Price sensitive demand	1%
Wind	0%
Oil	0%
Municipal waste	0%
Diesel	0%

Figure 2-6 Day-ahead load-weighted unit markup index: January through June 2010 (See 2009 SOM, Figure 2-6)



Unit Markup Characteristics

Table 2-35 Average, day-ahead marginal unit markup index (By primary fuel and unit type): January through June 2010 (See 2009 SOM, Table 2-41)

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	(0.07)	($2.63)
Diesel	Diesel	(0.24)	($16.12)
Municipal waste	Steam	0.01	$0.23
Natural gas	CT	0.05	$3.45
Natural gas	Diesel	(0.04)	($3.03)
Natural gas	Steam	(0.00)	($0.31)
Oil	Steam	0.01	$1.79
Wind	Wind	0.00	$0.00

Table 2-36 Average, day-ahead marginal unit markup index (By price category): January through June 2010 (See 2009 SOM, Table 2-42)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($2.78)
$25 to $50	(0.06)	($2.41)
$50 to $75	0.01	$0.57
$75 to $100	0.02	$0.30
$100 to $125	0.00	$0.36
$125 to $150	0.19	$25.78
> $150	0.15	$23.68

Markup Component of System Price

Table 2-37 Monthly markup components of day-ahead, load-weighted LMP: January through June 2010 (See 2009 SOM, Table 2-43)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.18)	($0.78)	($1.51)
Feb	($0.86)	($0.61)	($1.11)
Mar	($1.61)	($1.18)	($2.12)
Apr	($1.84)	($1.19)	($2.63)
May	($0.76)	($0.10)	($1.38)
Jun	($0.60)	($0.10)	($1.20)
Annual	($1.12)	($0.65)	($1.61)

Markup Component of Zonal Prices

Table 2-38 Day-ahead, average, zonal markup component: January through June 2010 (See 2009 SOM, Table 2-44)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.93)	($0.42)	($1.47)
AEP	($1.67)	($0.95)	($2.41)
AP	($1.02)	($0.39)	($1.67)
BGE	($0.89)	($0.48)	($1.32)
ComEd	($1.06)	($0.89)	($1.22)
DAY	($1.73)	($0.95)	($2.56)
DLCO	($1.60)	($0.90)	($2.37)
Dominion	($0.91)	($0.79)	($1.04)
DPL	($0.91)	($0.41)	($1.43)
JCPL	($0.94)	($0.43)	($1.50)
Met-Ed	($1.00)	($0.52)	($1.52)
PECO	($0.91)	($0.38)	($1.48)
PENELEC	($1.23)	($0.60)	($1.90)
Pepco	($0.79)	($0.37)	($1.24)
PPL	($0.91)	($0.35)	($1.51)
PSEG	($0.87)	($0.38)	($1.43)
RECO	($0.83)	($0.33)	($1.44)

Markup by System Price Levels

Table 2-39 Average, day-ahead markup (By price category): January through June 2010 (See 2009 SOM, Table 2-45)

	Average Markup Component	Frequency
Below $20	($3.89)	0%
$20 to $40	($2.50)	52%
$40 to $60	($0.47)	37%
$60 to $80	($1.40)	7%
$80 to $100	$1.77	2%
$100 to $120	$1.82	1%
$120 to $140	$10.49	0%
$140 to $160	$0.00	0%
Above $160	$0.00	0%

Markup Component by Fuel, Unit Type

Table 2-40 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through June 2010 (See 2009 SOM, Table 2-46)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.97)	87.0%
Diesel	Diesel	($0.01)	0.6%
Municipal waste	Steam	$0.00	(0.0%)
Natural gas	CT	$0.01	(0.5%)
Natural gas	Diesel	($0.00)	0.3%
Natural gas	Steam	($0.14)	12.4%
Oil	Steam	($0.00)	0.1%
Wind	Wind	$0.00	0.0%
Total		($1.12)	100.0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-41 Frequently mitigated units and associated units (By month): January through June 2010 (See 2009 SOM, Table 2-47)

	FMUs and AUs			Total Eligible for Any Adder
	Tier 1	Tier 2	Tier 3	
January	35	31	27	93
February	35	28	31	94
March	42	16	44	102
April	38	13	47	98
May	35	19	35	89
June	29	16	41	86

Table 2-42 Frequently mitigated units and associated units total months eligible: January through June 2010 (See 2009 SOM, Table 2-48)

Months Adder-Eligible	FMU & AU Count
1	2
2	4
3	16
4	13
5	10
6	67
Total	112

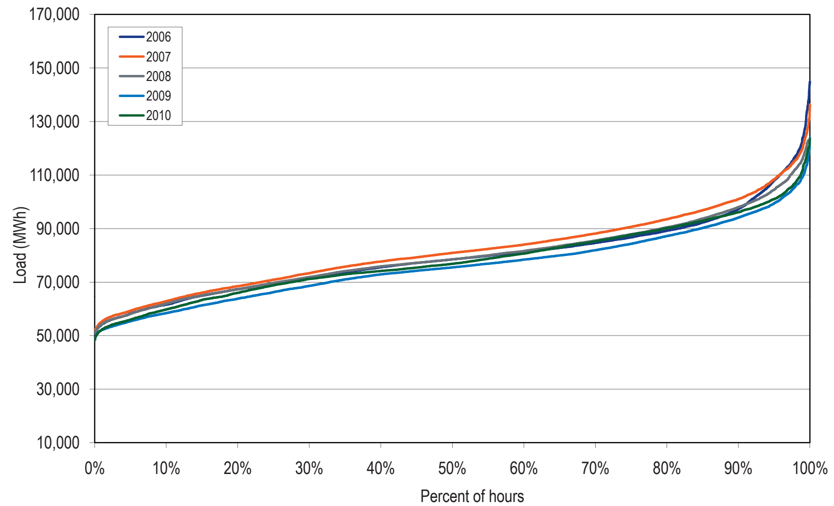
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 PJM real-time load duration curves: Calendar years 2006 through June 2010 (See 2009 SOM, Figure 2-7)



PJM Real-Time, Annual Average Load

Table 2-43 PJM real-time average load: Calendar years 1998 through June 2010 (See 2009 SOM, Table 2-49)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	76,035	75,471	13,260	(4.4%)	(3.8%)	(3.6%)
2010	78,106	76,831	13,643	2.7%	1.8%	2.9%

PJM Real-Time, Monthly Average Load

Figure 2-8 PJM real-time average load: Calendar years 2009 through June 2010 (See 2009 SOM, Figure 2-8)

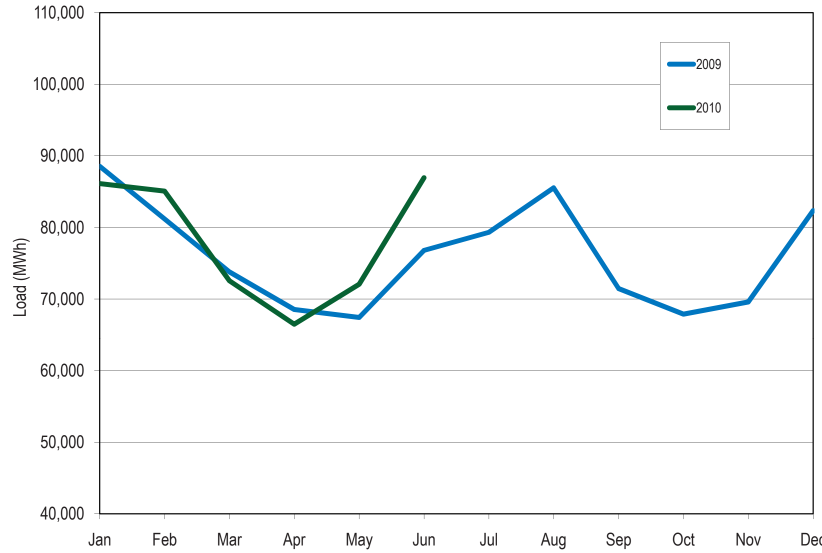


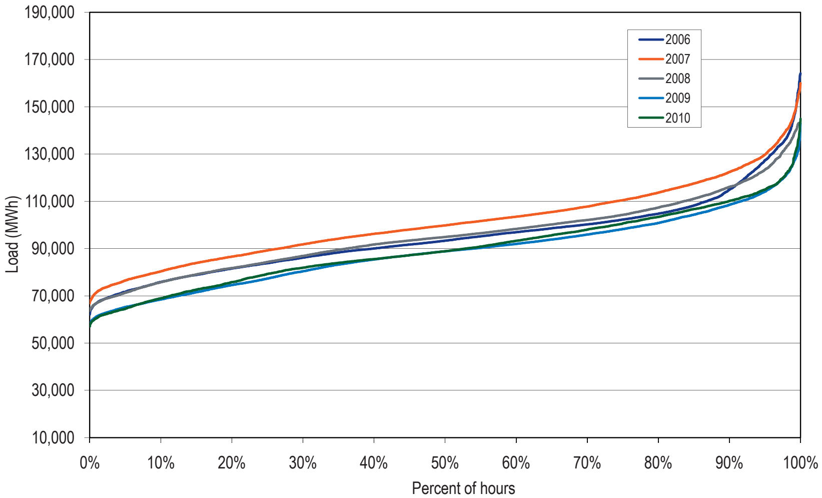
Table 2-44 PJM annual Summer THI, Winter WWP and average temperature: cooling, heating and shoulder months of 2006 through June 2010 (See 2009 SOM, Table 2-51)

	Summer THI	Winter WWP	Shoulder Average Temperature
2006	75.59	31.67	54.62
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	76.14	24.47	56.85

Day-Ahead Load

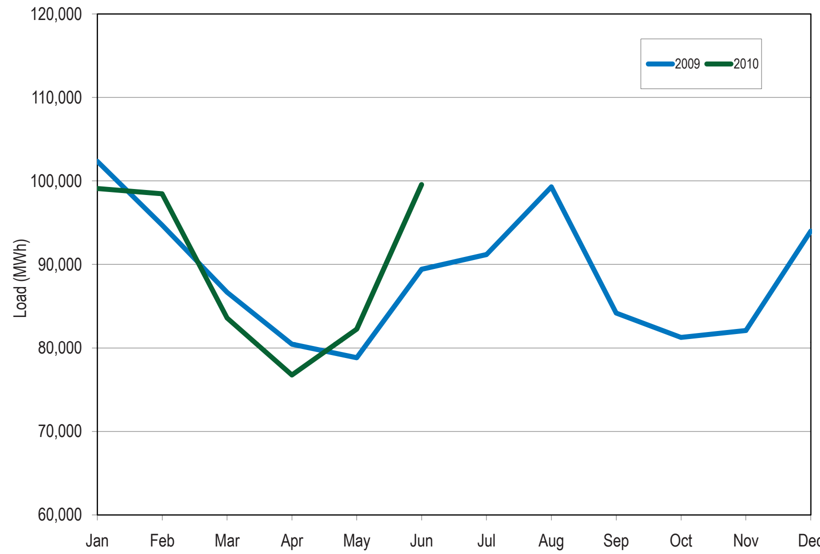
PJM Day-Ahead Load Duration

Figure 2-9 PJM day-ahead load duration curves: Calendar years 2006 through June 2010 (See 2009 SOM, Figure 2-9)



PJM Day-Ahead, Monthly Average Load

Figure 2-10 PJM day-ahead average load: Calendar years 2009 through June 2010 (See 2009 SOM, Figure 2-10)



PJM Day-Ahead, Annual Average Load

Table 2-45 PJM day-ahead average load: Calendar years 2000 through June 2010 (See 2009 SOM, Table 2-52)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	33,045	33,217	6,850	NA	NA	NA
2001	33,318	32,812	6,489	0.8%	(1.2%)	(5.3%)
2002	42,131	40,720	10,130	26.4%	24.1%	56.1%
2003	44,340	44,368	7,883	5.2%	9.0%	(22.2%)
2004	61,034	58,544	16,318	37.7%	32.0%	107.0%
2005	92,002	90,424	17,381	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)
2009	88,707	88,833	14,896	(7.1%)	(6.4%)	(3.5%)
2010	89,830	88,894	15,372	1.3%	0.1%	3.2%

Real-Time and Day-Ahead Load

Table 2-46 Cleared day-ahead and real-time load (MWh): January through June 2010 (See 2009 SOM, Table 2-53)

	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	72,503	1,137	16,191	89,830	78,106	11,724	(4,466)
Median	71,461	1,070	16,186	88,894	76,831	12,062	(4,123)
Standard deviation	12,724	397	2,651	15,372	13,643	1,728	(923)
Peak average	79,529	1,285	17,579	98,393	85,391	13,002	(4,577)
Peak median	78,690	1,196	17,459	97,111	84,389	12,722	(4,737)
Peak standard deviation	10,266	376	2,104	12,231	11,130	1,101	(1,003)
Off peak average	66,325	1,006	14,970	82,301	71,701	10,601	(4,370)
Off peak median	64,862	930	14,817	80,844	70,310	10,534	(4,283)
Off peak standard deviation	11,404	369	2,477	13,834	12,379	1,455	(1,021)

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): January through June 2010 (See 2009 SOM, Figure 2-11)

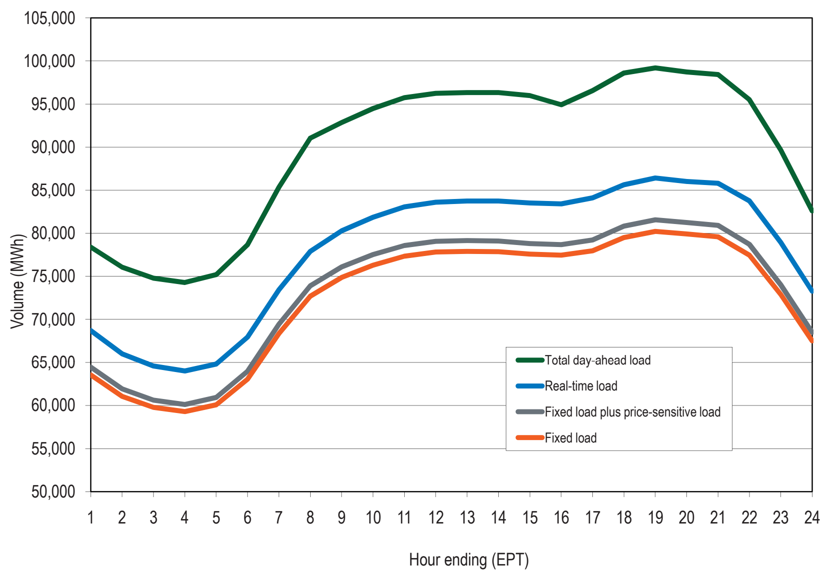
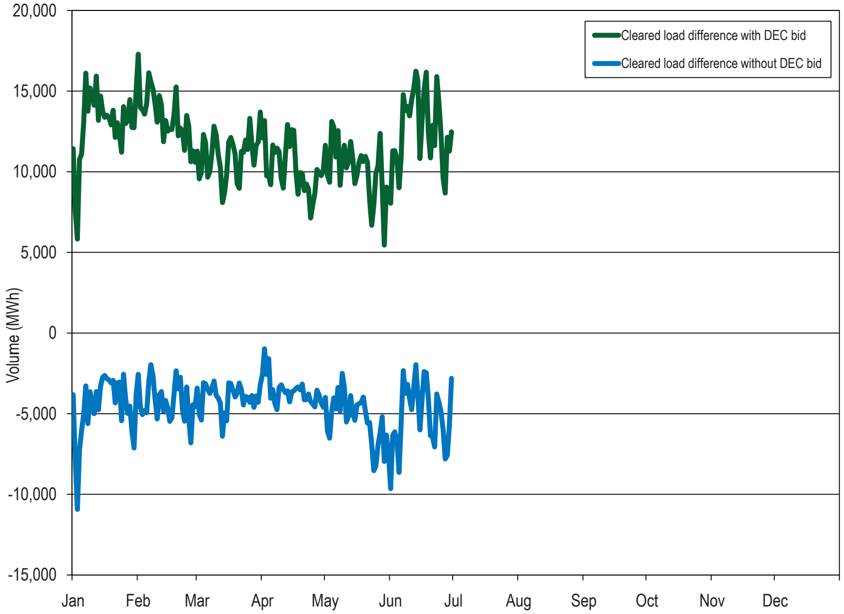


Figure 2-12 Day-ahead and real-time loads (Average daily volumes): January through June 2010 (New Figure)



Day-Ahead and Real-Time Generation

Table 2-47 Day-ahead and real-time generation (MWh): January through June 2010 (See 2009 SOM, Table 2-54)

	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	81,523	11,243	92,765	80,702	820	12,063
Median	80,593	11,146	91,802	79,546	1,047	12,256
Standard deviation	14,920	1,656	15,707	13,968	952	1,740
Peak average	89,403	12,160	101,563	88,043	1,360	13,520
Peak median	88,386	12,126	100,311	86,877	1,508	13,434
Peak standard deviation	11,799	1,463	12,454	11,405	394	1,049
Off peak average	74,593	10,436	85,030	74,248	345	10,782
Off peak median	73,299	10,448	83,490	72,645	654	10,845
Off peak standard deviation	13,905	1,372	14,122	12,777	1,127	1,345

Figure 2-13 Day-ahead and real-time generation (Average hourly volumes): January through June 2010 (See 2009 SOM, Figure 2-12)

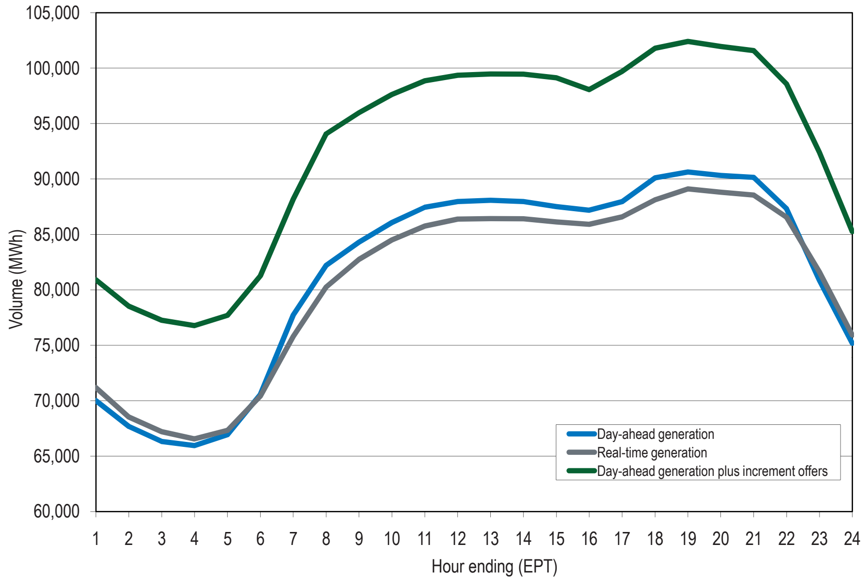
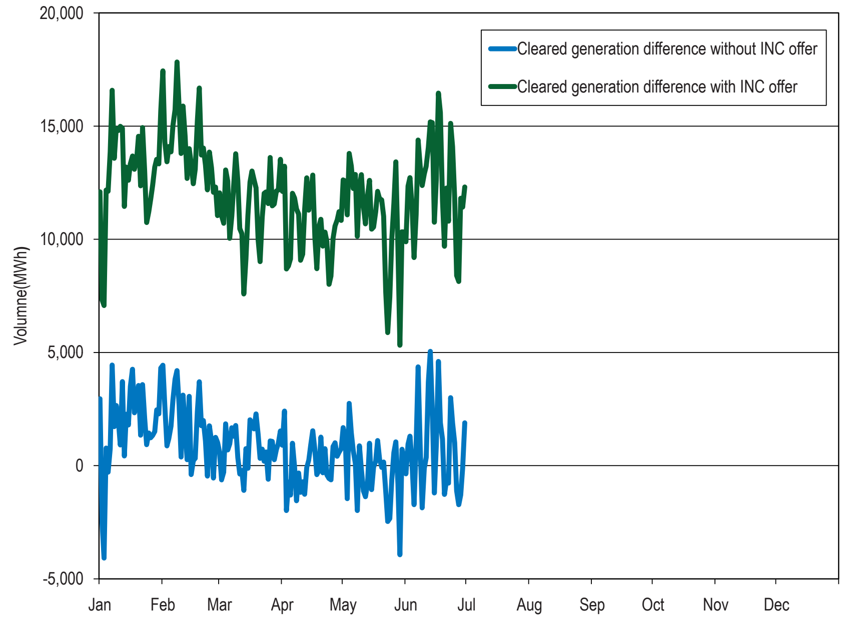


Figure 2-14 Day-ahead and real-time generation (Average daily volumes): January through June 2010 (New Figure)



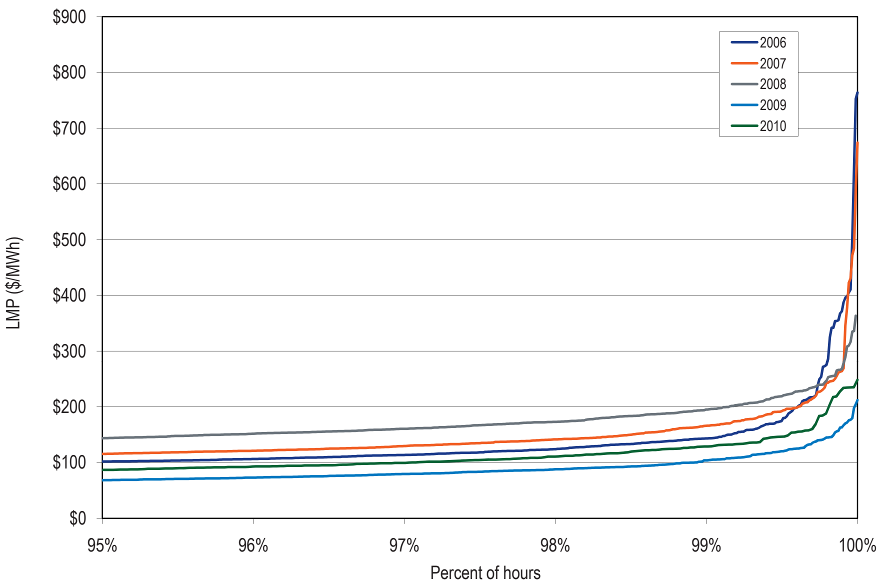
Locational Marginal Price (LMP)

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: Calendar years 2006 through June 2010 (See 2009 SOM, Figure 2-13)



PJM Real-Time, Annual Average LMP

Table 2-48 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 through June 2010 (See 2009 SOM, Table 2-55)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$43.27	$37.11	$22.20	16.7%	13.4%	29.7%

Zonal Real-Time, Annual Average LMP

Table 2-49 Zonal real-time, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-56)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AECO	$44.59	$47.67	$3.08	6.9%
AEP	$36.37	$37.85	$1.48	4.1%
AP	$41.77	$42.65	$0.87	2.1%
BGE	$45.22	$50.08	$4.86	10.8%
ComEd	$30.28	$33.60	$3.32	11.0%
DAY	$35.90	$37.68	$1.78	5.0%
DLCO	$34.49	$37.71	$3.22	9.3%
Dominion	$43.53	$49.34	$5.82	13.4%
DPL	$45.20	$48.14	$2.94	6.5%
JCPL	$44.92	$47.26	$2.34	5.2%
Met-Ed	$43.73	$46.36	$2.62	6.0%
PECO	$43.63	$46.72	$3.08	7.1%
PENELEC	$40.06	$40.77	$0.71	1.8%
Pepco	$44.77	$50.15	$5.39	12.0%
PPL	$43.14	$45.44	$2.30	5.3%
PSEG	$45.44	$48.45	$3.01	6.6%
RECO	$44.22	$46.44	$2.22	5.0%
PJM	$40.12	$43.27	$3.16	7.9%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-50 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-57)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
Delaware	$44.87	$47.44	$2.57	5.7%
Illinois	$30.28	$33.60	$3.32	11.0%
Indiana	$35.71	$36.87	$1.17	3.3%
Kentucky	$36.25	$38.34	$2.10	5.8%
Maryland	$45.20	$49.92	$4.72	10.4%
Michigan	$37.07	$37.45	$0.39	1.0%
New Jersey	$45.16	$47.97	$2.81	6.2%
North Carolina	$42.45	$47.56	$5.11	12.0%
Ohio	$35.69	$37.07	$1.38	3.9%
Pennsylvania	$41.88	$44.00	$2.12	5.1%
Tennessee	$36.34	$39.38	$3.04	8.4%
Virginia	$42.77	$48.06	$5.29	12.4%
West Virginia	$37.65	$38.13	$0.48	1.3%
District of Columbia	$44.92	$50.37	$5.45	12.1%

Hub Real-Time, Annual Average LMP

Table 2-51 Hub real-time, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-58)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AEP Gen Hub	$34.21	$35.37	$1.16	3.4%
AEP-DAY Hub	$35.87	$37.12	$1.24	3.5%
Chicago Gen Hub	$29.44	$32.79	$3.35	11.4%
Chicago Hub	$30.49	$33.77	$3.28	10.8%
Dominion Hub	$42.82	$48.01	$5.19	12.1%
Eastern Hub	$45.06	$48.15	$3.08	6.8%
N Illinois Hub	$30.07	$33.40	$3.33	11.1%
New Jersey Hub	$45.11	$47.86	$2.75	6.1%
Ohio Hub	$35.84	$37.16	$1.32	3.7%
West Interface Hub	$37.20	$40.10	$2.90	7.8%
Western Hub	$41.40	$43.87	$2.47	6.0%

Real-Time, Load-Weighted, Average LMP

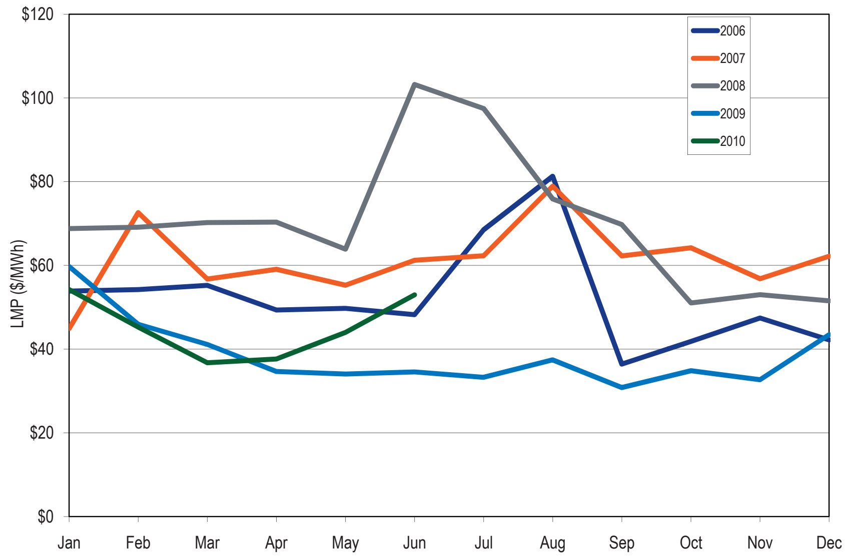
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-52 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through June 2010 (See 2009 SOM, Table 2-59)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$45.75	$38.78	$23.60	17.2%	13.3%	29.6%

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

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2006 through June 2010 (See 2009 SOM, Figure 2-14)



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

Table 2-53 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-60)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AECO	$46.77	$51.21	$4.44	9.5%
AEP	$38.30	$39.53	$1.22	3.2%
AP	$44.59	$44.66	$0.07	0.1%
BGE	$48.39	$53.92	$5.53	11.4%
ComEd	$32.25	$35.48	$3.23	10.0%
DAY	$37.77	$39.50	$1.73	4.6%
DLCO	$35.62	$39.37	$3.75	10.5%
Dominion	$46.89	$53.75	$6.86	14.6%
DPL	$48.77	$51.66	$2.89	5.9%
JCPL	$47.50	$50.97	$3.46	7.3%
Met-Ed	$46.64	$49.02	$2.38	5.1%
PECO	$46.05	$49.58	$3.53	7.7%
PENELEC	$42.08	$42.12	$0.03	0.1%
Pepco	$47.69	$54.16	$6.47	13.6%
PPL	$46.39	$47.93	$1.55	3.3%
PSEG	$47.42	$51.48	$4.06	8.6%
RECO	$46.29	$50.02	$3.72	8.0%
PJM	$42.48	$45.75	$3.27	7.7%

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

Table 2-54 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-61)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
Delaware	$47.92	$50.56	$2.63	5.5%
Illinois	$32.25	$35.48	$3.23	10.0%
Indiana	$37.00	$38.03	$1.03	2.8%
Kentucky	$39.03	$40.64	$1.61	4.1%
Maryland	$48.71	$53.98	$5.27	10.8%
Michigan	$38.50	$39.05	$0.55	1.4%
New Jersey	$47.34	$51.27	$3.93	8.3%
North Carolina	$45.76	$52.03	$6.27	13.7%
Ohio	$37.35	$38.54	$1.19	3.2%
Pennsylvania	$44.33	$46.17	$1.85	4.2%
Tennessee	$38.96	$42.26	$3.29	8.4%
Virginia	$46.17	$52.16	$5.98	13.0%
West Virginia	$40.16	$39.88	($0.28)	(0.7%)
District of Columbia	$46.88	$53.53	$6.65	14.2%

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

Fuel Cost

Figure 2-17 Spot average fuel price comparison: Calendar years 2009 through June 2010 (See 2009 SOM, Figure 2-15)

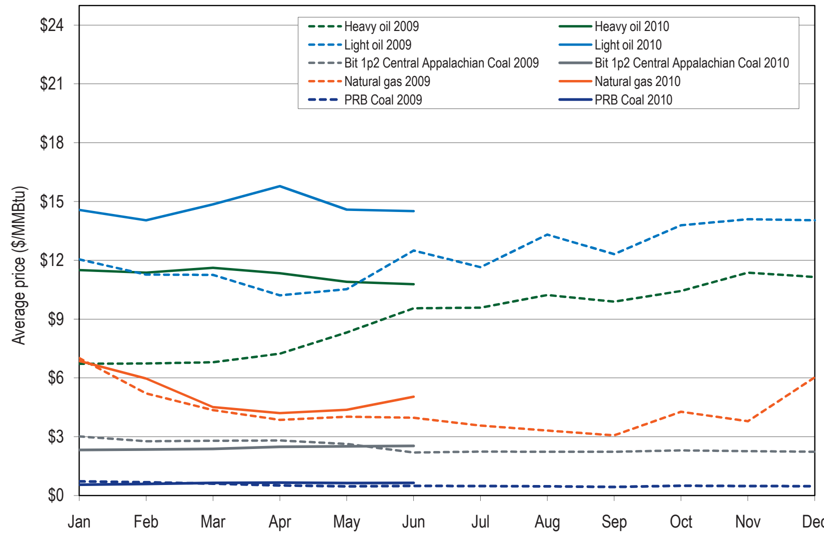


Figure 2-18 Spot average emission price comparison: Calendar years 2009 through June 2010 (See 2009 SOM, Figure 2-16)

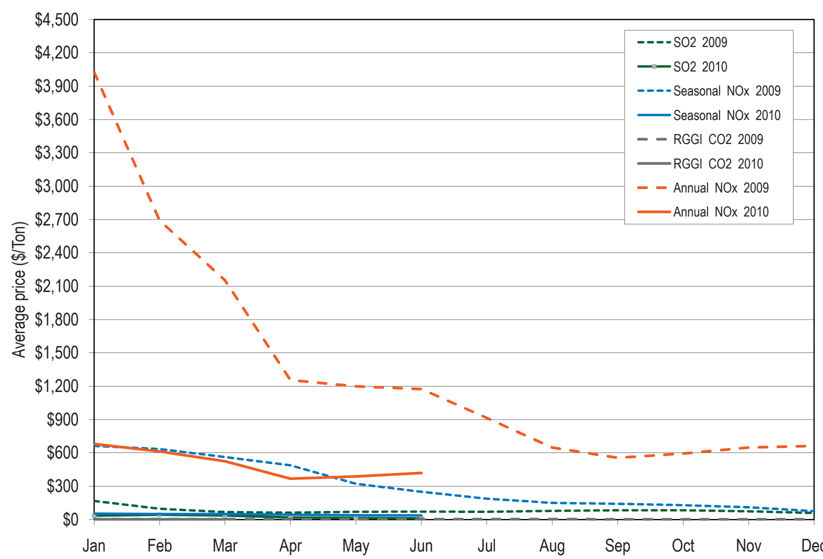


Table 2-55 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2009 SOM, Table 2-62)

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

Table 2-56 PJM real-time annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-63)

	2010 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$45.75	$49.81	8.9%
	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$42.48	$49.81	17.3%
	2009 Load-Weighted LMP	2010 Load-Weighted LMP	Change
Average	$42.48	$45.75	7.7%

Components of Real-Time, Load-Weighted LMP

Table 2-57 Components of PJM real-time, annual, load-weighted, average LMP: January 1, 2010, through June 30, 2010 (See 2009 SOM, Table 2-64)

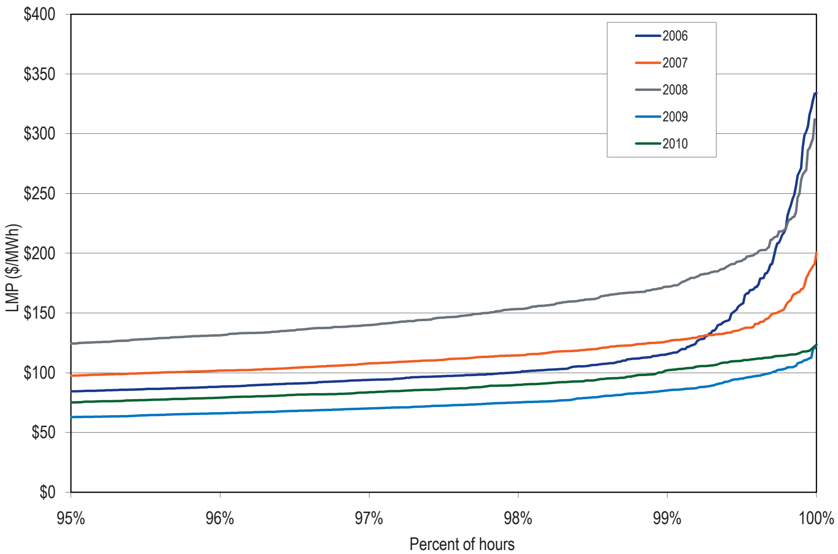
Element	Contribution to LMP	Percent
Coal	$19.61	42.9%
Gas	$18.06	39.5%
10% Cost Adder	$4.28	9.4%
VOM	$2.83	6.2%
NOX	$1.21	2.6%
Oil	$0.90	2.0%
CO2	$0.58	1.3%
Dispatch Differential	$0.33	0.7%
SO2	$0.25	0.6%
FMU Adder	$0.16	0.4%
NA	$0.13	0.3%
M2M Adder	$0.01	0.0%
Shadow Price Limit Adder	$0.01	0.0%
Offline CT Adder	$0.00	0.0%
Municipal Waste	($0.01)	(0.0%)
Markup	($1.15)	(2.5%)
UDS Override Differential	($1.47)	(3.2%)
LMP	$45.75	100.0%

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: Calendar years 2006 through June 2010 (See 2009 SOM, Figure 2-17)



PJM Day-Ahead, Annual Average LMP

Table 2-58 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 through June 2010 (See 2009 SOM, Table 2-65)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$43.81	$40.64	$15.66	18.4%	15.6%	16.9%

Zonal Day-Ahead, Annual Average LMP

Table 2-59 Zonal day-ahead, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-66)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AECO	$45.38	$48.54	$3.16	7.0%
AEP	$36.19	$38.07	$1.88	5.2%
AP	$41.11	$43.14	$2.03	4.9%
BGE	$46.01	$51.38	$5.37	11.7%
ComEd	$30.42	$34.01	$3.58	11.8%
DAY	$35.34	$37.60	$2.26	6.4%
DLCO	$34.04	$38.37	$4.32	12.7%
Dominion	$44.17	$50.36	$6.19	14.0%
DPL	$45.80	$48.70	$2.90	6.3%
JCPL	$45.58	$48.27	$2.69	5.9%
Met-Ed	$44.24	$47.38	$3.14	7.1%
PECO	$44.67	$47.81	$3.14	7.0%
PENELEC	$40.30	$42.38	$2.08	5.2%
Pepco	$45.60	$51.71	$6.10	13.4%
PPL	$43.82	$46.45	$2.63	6.0%
PSEG	$46.27	$49.27	$3.00	6.5%
RECO	$45.06	$48.07	$3.01	6.7%
PJM	$40.01	$43.81	$3.80	9.5%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-60 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-67)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
Delaware	$45.21	$48.02	$2.81	6.2%
Illinois	$30.42	$34.01	$3.58	11.8%
Indiana	$35.47	$37.01	$1.54	4.3%
Kentucky	$35.95	$38.31	$2.36	6.6%
Maryland	$45.89	$51.14	$5.25	11.4%
Michigan	$36.78	$37.51	$0.73	2.0%
New Jersey	$45.94	$48.88	$2.94	6.4%
North Carolina	$43.03	$48.75	$5.72	13.3%
Ohio	$35.29	$37.04	$1.76	5.0%
Pennsylvania	$42.33	$44.97	$2.64	6.2%
Tennessee	$36.51	$39.64	$3.13	8.6%
Virginia	$43.39	$49.18	$5.79	13.3%
West Virginia	$37.38	$38.47	$1.10	2.9%
District of Columbia	$45.68	$51.92	$6.24	13.7%

Day-Ahead, Load-Weighted, Average LMP

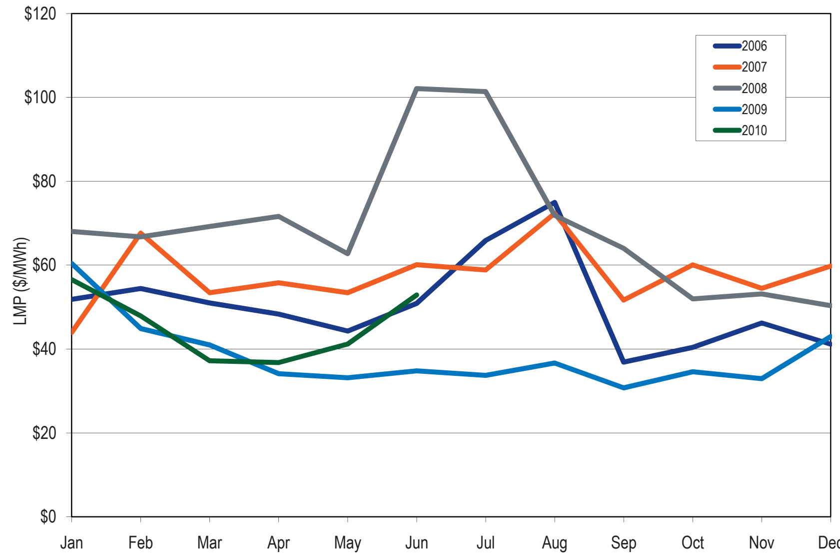
PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-61 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through June 2010 (See 2009 SOM, Table 2-68)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$46.12	$42.50	$16.54	18.8%	15.9%	17.9%

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

Figure 2-20 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2006 through June 2010 (See 2009 SOM, Figure 2-18)



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-62 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2009 to 2010 (See 2009 SOM, Table 2-69)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AECO	$48.09	$52.63	$4.54	9.4%
AEP	$37.95	$39.68	$1.73	4.6%
AP	$43.83	$45.14	$1.31	3.0%
BGE	$49.12	$55.13	$6.01	12.2%
ComEd	$31.72	$35.49	$3.77	11.9%
DAY	$36.99	$39.30	$2.31	6.2%
DLCO	$35.10	$40.16	$5.06	14.4%
Dominion	$47.39	$54.80	$7.41	15.6%
DPL	$48.86	$52.03	$3.17	6.5%
JCPL	$47.94	$51.29	$3.35	7.0%
Met-Ed	$47.29	$49.92	$2.63	5.6%
PECO	$47.08	$50.48	$3.40	7.2%
PENELEC	$42.35	$43.66	$1.31	3.1%
Pepco	$48.20	$54.53	$6.33	13.1%
PPL	$46.72	$48.88	$2.16	4.6%
PSEG	$48.45	$51.91	$3.46	7.1%
RECO	$47.59	$51.58	$3.99	8.4%
PJM	$42.21	$46.12	$3.91	9.3%

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

Table 2-63 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-70)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
Delaware	$48.05	$51.06	$3.02	6.3%
Illinois	$31.72	$35.49	$3.77	11.9%
Indiana	$36.72	$38.35	$1.63	4.5%
Kentucky	$38.34	$40.18	$1.84	4.8%
Maryland	$49.12	$54.56	$5.43	11.1%
Michigan	$37.93	$38.81	$0.89	2.3%
New Jersey	$48.22	$51.80	$3.57	7.4%
North Carolina	$46.44	$52.99	$6.55	14.1%
Ohio	$36.89	$38.46	$1.57	4.3%
Pennsylvania	$44.69	$46.95	$2.25	5.0%
Tennessee	$38.72	$42.08	$3.36	8.7%
Virginia	$46.51	$53.23	$6.72	14.4%
West Virginia	$39.63	$40.20	$0.56	1.4%
District of Columbia	$47.70	$54.37	$6.67	14.0%

Components of Day-Ahead, Load-Weighted LMP

Table 2-64 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-71)

Element	Contribution to LMP	Percent
INC	$17.41	37.7%
DEC	$11.91	25.8%
Coal	$7.05	15.3%
Natural gas	$5.79	12.6%
Price sensitive demand	$1.56	3.4%
10% Cost offer	$1.45	3.1%
VOM	$0.85	1.8%
Transaction	$0.50	1.1%
NOx	$0.39	0.8%
CO2	$0.19	0.4%
Oil	$0.10	0.2%
SO2	$0.09	0.2%
Diesel	$0.02	0.0%
Constrained off	$0.00	0.0%
FMU adder	$0.00	0.0%
Markup	($1.12)	(2.4%)
NA	($0.08)	(0.2%)
Total	$46.12	100.0%

Marginal Losses

Table 2-65 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through June 2010 (See 2009 SOM, Table 2-72)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$43.27	$43.18	$0.05	$0.04

Table 2-66 Zonal real-time, simple average LMP components (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-73)

	2009 (Jan - Jun)				2010 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$44.59	$40.04	$2.60	$1.95	$47.67	$43.18	$2.24	$2.25
AEP	$36.37	$40.04	($2.38)	($1.28)	$37.85	$43.18	($3.81)	($1.52)
AP	$41.77	$40.04	$1.79	($0.05)	$42.65	$43.18	($0.37)	($0.17)
BGE	$45.22	$40.04	$3.49	$1.69	$50.08	$43.18	$4.72	$2.18
ComEd	$30.28	$40.04	($7.26)	($2.50)	$33.60	$43.18	($6.74)	($2.84)
DAY	$35.90	$40.04	($3.22)	($0.92)	$37.68	$43.18	($4.52)	($0.98)
DLCO	$34.49	$40.04	($4.12)	($1.43)	$37.71	$43.18	($3.88)	($1.59)
Dominion	$43.53	$40.04	$2.90	$0.59	$49.34	$43.18	$5.35	$0.81
DPL	$45.20	$40.04	$3.02	$2.14	$48.14	$43.18	$2.52	$2.44
JCPL	$44.92	$40.04	$2.72	$2.17	$47.26	$43.18	$1.79	$2.29
Met-Ed	$43.73	$40.04	$2.70	$1.00	$46.36	$43.18	$2.04	$1.13
PECO	$43.63	$40.04	$2.19	$1.41	$46.72	$43.18	$1.92	$1.61
PENELEC	$40.06	$40.04	$0.09	($0.07)	$40.77	$43.18	($2.13)	($0.29)
Pepco	$44.77	$40.04	$3.60	$1.13	$50.15	$43.18	$5.57	$1.41
PPL	$43.14	$40.04	$2.29	$0.81	$45.44	$43.18	$1.36	$0.90
PSEG	$45.44	$40.04	$3.17	$2.23	$48.45	$43.18	$2.96	$2.31
RECO	$44.22	$40.04	$2.21	$1.98	$46.44	$43.18	$1.25	$2.00

Table 2-67 Hub real-time, simple average LMP components (Dollars per MWh): January through June 2010 (See 2009 SOM, 2-74)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.37	$43.18	($4.86)	($2.95)
AEP-DAY Hub	$37.12	$43.18	($4.34)	($1.73)
Chicago Gen Hub	$32.79	$43.18	($7.00)	($3.38)
Chicago Hub	$33.77	$43.18	($6.59)	($2.82)
Dominion Hub	$48.01	$43.18	$4.52	$0.30
Eastern Hub	$48.15	$43.18	$2.35	$2.62
N Illinois Hub	$33.40	$43.18	($6.73)	($3.05)
New Jersey Hub	$47.86	$43.18	$2.43	$2.25
Ohio Hub	$37.16	$43.18	($4.34)	($1.68)
West Interface Hub	$40.10	$43.18	($1.68)	($1.40)
Western Hub	$43.87	$43.18	$0.93	($0.25)

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

Table 2-68 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-75)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$51.21	$46.08	$2.71	$2.42
AEP	$39.53	$45.29	($4.18)	($1.59)
AP	$44.66	$45.45	($0.60)	($0.19)
BGE	$53.92	$46.03	$5.54	$2.35
ComEd	$35.48	$45.16	($6.79)	($2.89)
DAY	$39.50	$45.49	($5.02)	($0.97)
DLCO	$39.37	$45.19	($4.13)	($1.69)
Dominion	$53.75	$46.37	$6.49	$0.89
DPL	$51.66	$46.29	$2.71	$2.66
JCPL	$50.97	$46.35	$2.16	$2.45
Met-Ed	$49.02	$45.56	$2.27	$1.19
PECO	$49.58	$45.71	$2.18	$1.69
PENELEC	$42.12	$44.90	($2.45)	($0.33)
Pepco	$54.16	$46.11	$6.55	$1.50
PPL	$47.93	$45.52	$1.48	$0.94
PSEG	$51.48	$45.73	$3.33	$2.42
RECO	$50.02	$46.27	$1.62	$2.13
PJM	$45.75	$45.65	$0.06	$0.04

Table 2-69 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 through June 2010 (See 2009 SOM, Table 2-76)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)
2010	$43.81	$43.74	$0.07	$0.00

Table 2-70 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-77)

	2009 (Jan - Jun)				2010 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$45.38	$40.27	$2.61	$2.49	$48.54	$43.74	$2.14	$2.66
AEP	$36.19	$40.27	($2.41)	($1.67)	$38.07	$43.74	($3.52)	($2.16)
AP	$41.11	$40.27	$0.75	$0.08	$43.14	$43.74	($0.45)	($0.16)
BGE	$46.01	$40.27	$3.72	$2.02	$51.38	$43.74	$4.75	$2.89
ComEd	$30.42	$40.27	($6.40)	($3.45)	$34.01	$43.74	($5.95)	($3.78)
DAY	$35.34	$40.27	($3.37)	($1.57)	$37.60	$43.74	($4.25)	($1.89)
DLCO	$34.04	$40.27	($4.56)	($1.68)	$38.37	$43.74	($3.47)	($1.91)
Dominion	$44.17	$40.27	$2.93	$0.96	$50.36	$43.74	$5.20	$1.42
DPL	$45.80	$40.27	$2.92	$2.61	$48.70	$43.74	$2.26	$2.70
JCPL	$45.58	$40.27	$2.51	$2.80	$48.27	$43.74	$1.56	$2.97
Met-Ed	$44.24	$40.27	$2.69	$1.28	$47.38	$43.74	$2.22	$1.42
PECO	$44.67	$40.27	$2.43	$1.97	$47.81	$43.74	$1.87	$2.20
PENELEC	$40.30	$40.27	($0.01)	$0.04	$42.38	$43.74	($1.50)	$0.14
Pepco	$45.60	$40.27	$3.67	$1.66	$51.71	$43.74	$5.75	$2.21
PPL	$43.82	$40.27	$2.46	$1.09	$46.45	$43.74	$1.58	$1.12
PSEG	$46.27	$40.27	$2.99	$3.00	$49.27	$43.74	$2.34	$3.18
RECO	$45.06	$40.27	$2.06	$2.72	$48.07	$43.74	$1.52	$2.80

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

Table 2-71 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-78)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$52.63	$47.19	$2.46	$2.97
AEP	$39.68	$45.85	($3.91)	($2.26)
AP	$45.14	$45.99	($0.67)	($0.18)
BGE	$55.13	$46.52	$5.49	$3.12
ComEd	$35.49	$45.44	($6.06)	($3.88)
DAY	$39.30	$46.01	($4.75)	($1.95)
DLCO	$40.16	$45.78	($3.61)	($2.01)
Dominion	$54.80	$46.85	$6.41	$1.54
DPL	$52.03	$46.72	$2.41	$2.90
JCPL	$51.29	$46.46	$1.67	$3.16
Met-Ed	$49.92	$46.02	$2.42	$1.49
PECO	$50.48	$46.18	$1.99	$2.32
PENELEC	$43.66	$45.25	($1.70)	$0.11
Pepco	$54.53	$45.82	$6.37	$2.33
PPL	$48.88	$46.01	$1.68	$1.18
PSEG	$51.91	$46.09	$2.48	$3.34
RECO	$51.58	$46.90	$1.67	$3.01
PJM	$46.12	$46.04	$0.08	($0.00)

Marginal Loss Accounting

Monthly Marginal Loss Costs

Table 2-72 Marginal loss costs by type (Dollars (Millions)): January through June 2010 (See 2009 SOM, Table 2-79)

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$45.5	($136.3)	$7.0	$188.9	$1.2	($2.8)	($4.0)	$0.0	$188.9
Feb	$31.6	($100.1)	$3.0	$134.7	$0.4	($0.6)	($1.3)	($0.4)	$134.3
Mar	$21.0	($70.5)	$2.7	$94.2	$0.2	($0.2)	($1.2)	($0.8)	$93.4
Apr	$16.8	($59.9)	$3.8	$80.4	($0.2)	$0.1	($1.7)	($2.0)	$78.4
May	$17.6	($77.6)	$6.0	$101.2	$0.4	($1.3)	($3.3)	($1.6)	$99.6
Jun	$20.3	($127.4)	$10.8	$158.5	$3.2	($0.3)	($5.8)	($2.3)	$156.3
Total	$152.7	($571.8)	$33.5	$757.9	$5.2	($5.1)	($17.3)	($7.0)	$750.9

Zonal Marginal Loss Costs

Table 2-73 Marginal loss costs by control zone and type (Dollars (Millions)): January through June 2010 (See 2009 SOM, Table 2-80)

	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	$14.3	$3.6	$0.1	$10.8	$1.0	($0.2)	($0.0)	$1.2	$11.9
AEP	($35.7)	($171.8)	$10.7	$146.9	($1.4)	$1.7	($1.4)	($4.5)	$142.3
AP	($3.0)	($60.0)	$6.0	$63.0	$1.6	$2.7	($3.7)	($4.9)	$58.1
BGE	$42.5	$13.4	$2.1	$31.2	$2.9	($2.0)	($1.7)	$3.3	$34.5
ComEd	($107.0)	($244.6)	$0.9	$138.6	($2.1)	($1.1)	($1.1)	($2.0)	$136.5
DAY	($2.8)	($32.2)	$4.7	$34.1	($0.0)	$1.0	($4.1)	($5.1)	$29.0
DLCO	($20.4)	($32.4)	$0.1	$12.2	($1.3)	($0.3)	($0.1)	($1.0)	$11.1
Dominion	$61.2	($20.4)	$3.9	$85.4	$1.6	($0.6)	($1.9)	$0.3	$85.7
DPL	$27.4	$4.7	$0.4	$23.2	($1.0)	($0.7)	($0.3)	($0.5)	$22.7
JCPL	$35.1	$11.9	$0.2	$23.4	$0.4	($0.7)	($0.2)	$1.0	$24.4
Met-Ed	$11.8	$1.7	$0.1	$10.1	$0.0	($0.2)	($0.1)	$0.2	$10.3
PECO	$33.7	$11.6	$0.0	$22.1	($0.2)	($0.9)	($0.0)	$0.7	$22.8
PENELEC	($11.4)	($46.0)	$0.0	$34.5	$2.4	($2.2)	$0.1	$4.6	$39.2
Pepco	$61.9	$29.0	$2.3	$35.1	($1.9)	($0.4)	($1.6)	($3.1)	$32.0
PJM	($37.5)	($53.7)	($5.7)	$10.6	$2.2	($5.8)	$4.4	$12.4	$22.9
PPL	$23.3	($5.0)	$0.9	$29.1	$1.0	$0.5	($0.0)	$0.5	$29.6
PSEG	$57.5	$18.2	$6.8	$46.1	($0.4)	$4.4	($5.6)	($10.4)	$35.7
RECO	$2.0	$0.3	$0.0	$1.7	$0.2	($0.2)	($0.0)	$0.4	$2.1
Total	$152.7	($571.8)	$33.5	$757.9	$5.2	($5.1)	($17.3)	($7.0)	$750.9

Table 2-74 Monthly marginal loss costs by control zone (Dollars (Millions)): January through June 2010 (See 2009 SOM, Table 2-81)

	Marginal Loss Costs by Control Zone (Millions)						
	Jan	Feb	Mar	Apr	May	Jun	Grand Total
AECO	$2.6	$1.5	$1.4	$1.4	$1.6	$3.3	$11.9
AEP	$40.0	$25.9	$16.4	$13.8	$14.8	$31.5	$142.3
AP	$13.7	$11.2	$6.8	$6.5	$8.4	$11.3	$58.1
BGE	$8.8	$6.7	$3.7	$3.3	$4.8	$7.3	$34.5
ComEd	$36.1	$23.9	$19.8	$16.2	$16.9	$23.7	$136.5
DAY	$6.6	$5.3	$4.2	$2.6	$4.6	$5.6	$29.0
DLCO	$3.0	$2.3	$1.6	$1.3	$1.4	$1.5	$11.1
Dominion	$20.1	$15.9	$9.0	$8.9	$10.8	$21.0	$85.7
DPL	$5.7	$3.6	$2.6	$2.8	$3.2	$4.7	$22.7
JCPL	$6.3	$4.0	$3.3	$2.3	$3.3	$5.1	$24.4
Met-Ed	$2.8	$1.6	$1.4	$1.0	$1.4	$2.1	$10.3
PECO	$4.2	$3.7	$2.3	$1.9	$3.6	$7.1	$22.8
PENELEC	$10.4	$7.2	$3.6	$3.6	$5.8	$8.6	$39.2
Pepco	$6.7	$5.7	$4.5	$3.8	$5.0	$6.4	$32.0
PJM	$5.5	$3.7	$2.9	$2.4	$5.2	$3.2	$22.9
PPL	$8.8	$6.3	$3.7	$2.2	$3.2	$5.4	$29.6
PSEG	$7.0	$5.4	$5.8	$4.3	$5.3	$7.9	$35.7
RECO	$0.5	$0.2	$0.2	$0.2	$0.3	$0.5	$2.1
Total	$188.9	$134.3	$93.4	$78.4	$99.6	$156.3	$750.9

Virtual Offers and Bids

Table 2-75 Monthly volume of cleared and submitted INCs, DECs: January through June 2010 (See 2009 SOM, Table 2-82)

	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	11,144	21,634	282	936	17,513	29,406	266	893
Feb	12,387	23,827	387	1,122	17,602	28,542	270	883
Mar	10,811	21,062	308	915	15,019	24,968	253	763
Apr	10,512	19,940	289	784	13,875	24,458	246	705
May	11,165	19,744	218	806	15,556	25,194	223	787
Jun	11,534	22,956	254	1,496	17,689	27,422	258	1,246
Jul								
Aug								
Sep								
Oct								
Nov								
Dec								
Annual	11,243	21,490	288	1,006	16,191	26,642	252	879

Table 2-76 Type of day-ahead marginal units: January through June 2010 (See 2009 SOM, Table 2-83)

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	16.5%	30.9%	32.5%	19.4%	0.7%
Feb	14.9%	34.1%	24.3%	26.1%	0.6%
Mar	10.6%	29.9%	34.1%	24.7%	0.7%
Apr	11.5%	32.9%	32.8%	22.5%	0.3%
May	12.3%	36.0%	28.6%	22.5%	0.6%
Jun	14.1%	35.2%	27.8%	22.5%	0.5%
Annual	13.3%	33.1%	30.1%	22.9%	0.6%

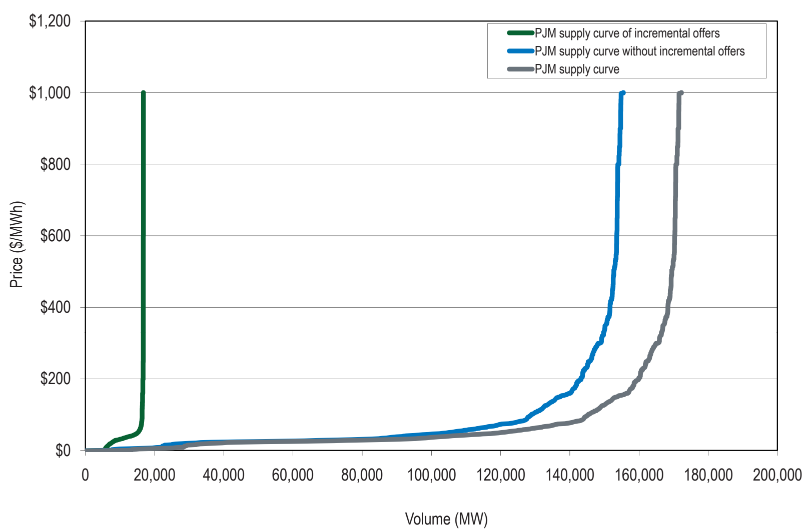
Table 2-77 PJM virtual bids by type of bid parent organization (MW): January through June 2010 (See 2009 SOM, Table 2-84)

	Category	Total Virtual Bids MW	Percentage
2010	Financial	60,824,903	29.1%
2010	Physical	148,212,716	70.9%
2010	Total	209,037,618	100%

Table 2-78 PJM virtual bids by top ten locations (MW): January through June 2010 (See 2009 SOM, Table 2-85)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	30,997,867.3	38,042,351.1	69,040,218.4
N ILLINOIS HUB	HUB	4,946,101.1	5,334,212.4	10,280,313.5
AEP-DAYTON HUB	HUB	2,927,074.9	3,726,855.4	6,653,930.3
PSEG	ZONE	1,397,499.8	3,468,094.5	4,865,594.3
Pepco	ZONE	3,505,342.4	820,900.3	4,326,242.7
PPL	ZONE	242,258.5	3,935,110.3	4,177,368.8
BGE	ZONE	2,125,414.0	1,729,223.7	3,854,637.7
JCPL	ZONE	2,273,216.3	1,562,999.4	3,836,215.7
MISO	INTERFACE	727,823.2	1,505,247.1	2,233,070.3
IMO	INTERFACE	1,483,146.6	615,369.3	2,098,515.9

Figure 2-21 PJM day-ahead aggregate supply curves: 2010 example day (See 2009 SOM, Figure 2-19)



Price Convergence

Table 2-79 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-86)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$43.81	$43.27	($0.54)	(1.2%)
Median	$40.64	$37.11	($3.53)	(9.5%)
Standard deviation	$15.66	$22.20	$6.54	29.5%

Table 2-80 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 through June 2010 (See 2009 SOM, Table 2-87)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$31.97	$30.36	($1.61)	(5.3%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.0%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$43.81	$43.27	($0.54)	(1.2%)

Table 2-81 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2006 through June 2010 (See 2009 SOM, Table 2-88)

	2006		2007		2008		2009		2010	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	1	0.01%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	1	0.02%	0	0.00%	1	0.01%	0	0.00%	0	0.00%
($100) to ($50)	9	0.13%	33	0.38%	88	1.01%	3	0.03%	6	0.14%
($50) to $0	5,205	59.54%	4,600	52.89%	5,120	59.30%	5,108	58.34%	2,890	66.68%
$0 to $50	3,372	98.04%	3,827	96.58%	3,247	96.27%	3,603	99.47%	1,366	98.13%
$50 to $100	152	99.77%	255	99.49%	284	99.50%	41	99.94%	69	99.72%
$100 to $150	9	99.87%	31	99.84%	37	99.92%	5	100.00%	5	99.84%
$150 to $200	4	99.92%	5	99.90%	4	99.97%	0	100.00%	7	100.00%
$200 to $250	1	99.93%	1	99.91%	2	99.99%	0	100.00%	0	100.00%
$250 to $300	3	99.97%	3	99.94%	0	99.99%	0	100.00%	0	100.00%
$300 to $350	0	99.97%	2	99.97%	1	100.00%	0	100.00%	0	100.00%
$350 to $400	1	99.98%	1	99.98%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	99.98%	1	99.99%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	1	99.99%	1	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-22 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through June 2010 (See 2009 SOM, Figure 2-20)

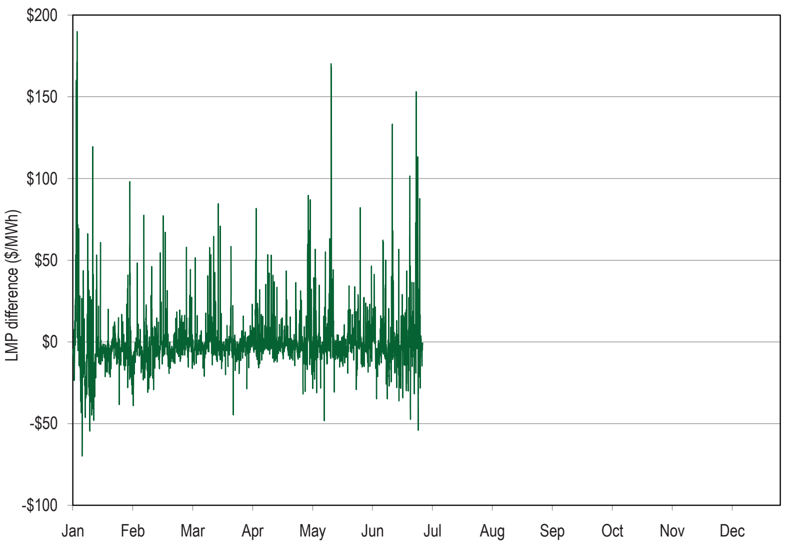


Figure 2-23 Monthly simple average of real-time minus day-ahead LMP: January through June 2010 (See 2009 SOM, Figure 2-21)

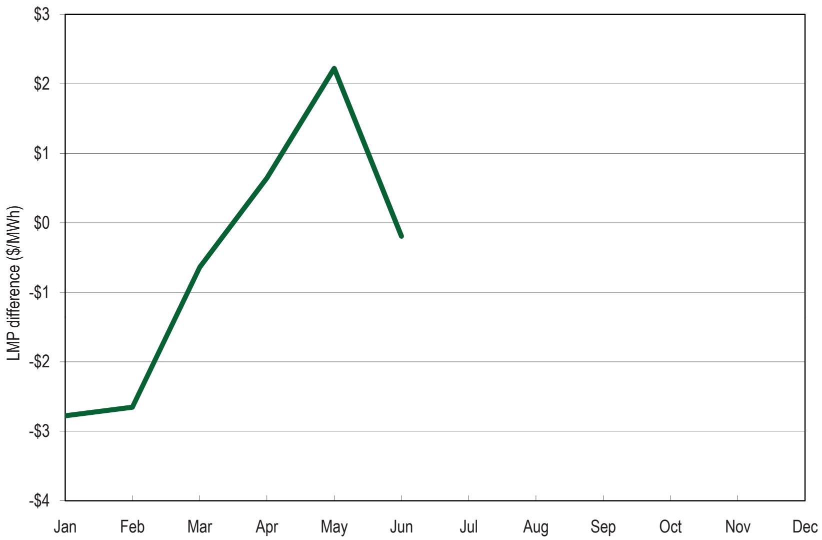
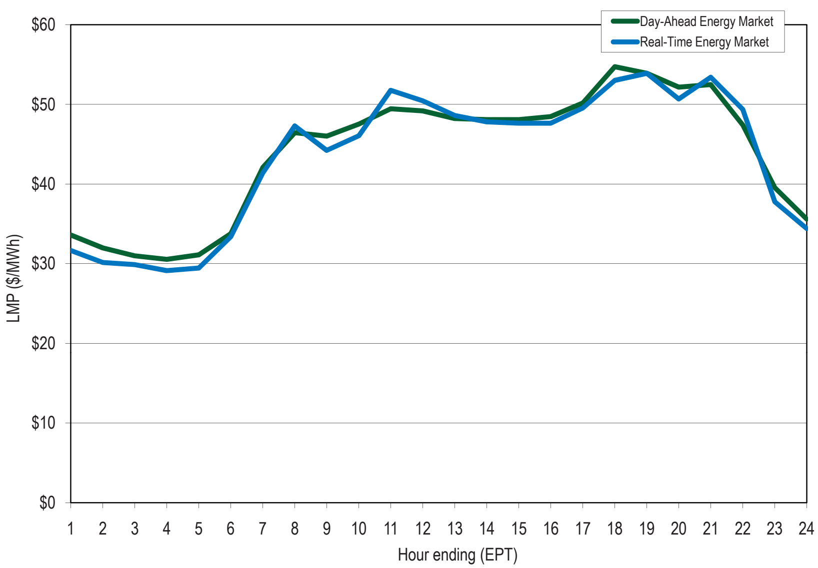


Figure 2-24 PJM system simple hourly average LMP: January through June 2010 (See 2009 SOM, Figure 2-22)



Zonal Price Convergence

Table 2-82 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-89)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$48.54	$47.67	($0.87)	(1.8%)
AEP	$38.07	$37.85	($0.22)	(0.6%)
AP	$43.14	$42.65	($0.50)	(1.2%)
BGE	$51.38	$50.08	($1.30)	(2.6%)
ComEd	$34.01	$33.60	($0.41)	(1.2%)
DAY	$37.60	$37.68	$0.08	0.2%
DLCO	$38.37	$37.71	($0.66)	(1.7%)
Dominion	$50.36	$49.34	($1.02)	(2.1%)
DPL	$48.70	$48.14	($0.56)	(1.2%)
JCPL	$48.27	$47.26	($1.01)	(2.1%)
Met-Ed	$47.38	$46.36	($1.03)	(2.2%)
PECO	$47.81	$46.72	($1.10)	(2.3%)
PENELEC	$42.38	$40.77	($1.61)	(3.9%)
Pepco	$51.71	$50.15	($1.55)	(3.1%)
PPL	$46.45	$45.44	($1.01)	(2.2%)
PSEG	$49.27	$48.45	($0.82)	(1.7%)
RECO	$48.07	$46.44	($1.63)	(3.5%)

Price Convergence by Jurisdiction

Table 2-83 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-90)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$48.02	$47.44	($0.58)	(1.2%)
Illinois	$34.01	$33.60	($0.41)	(1.2%)
Indiana	$37.01	$36.87	($0.14)	(0.4%)
Kentucky	$38.31	$38.34	$0.03	0.1%
Maryland	$51.14	$49.92	($1.22)	(2.4%)
Michigan	$37.51	$37.45	($0.06)	(0.2%)
New Jersey	$48.88	$47.97	($0.91)	(1.9%)
North Carolina	$48.75	$47.56	($1.19)	(2.5%)
Ohio	$37.04	$37.07	$0.03	0.1%
Pennsylvania	$44.97	$44.00	($0.98)	(2.2%)
Tennessee	$39.64	$39.38	($0.26)	(0.7%)
Virginia	$49.18	$48.06	($1.13)	(2.3%)
West Virginia	$38.47	$38.13	($0.35)	(0.9%)
District of Columbia	$51.92	$50.37	($1.55)	(3.1%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-84 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2009 to June 30, 2010 (See 2009 SOM, Table 2-91)

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.6%	15.4%	72.0%	11.9%	17.4%	70.7%	(0.7%)	2.0%	(1.3%)
Feb	13.4%	14.5%	72.1%	13.3%	18.1%	68.6%	(0.1%)	3.6%	(3.5%)
Mar	13.8%	16.7%	69.5%	12.7%	18.2%	69.1%	(1.0%)	1.5%	(0.4%)
Apr	13.5%	17.2%	69.3%	12.5%	19.2%	68.2%	(0.9%)	2.0%	(1.1%)
May	14.6%	18.8%	66.7%	11.5%	19.9%	68.6%	(3.1%)	1.1%	2.0%
Jun	12.5%	16.5%	71.0%	10.4%	19.0%	70.6%	(2.1%)	2.5%	(0.4%)
Jul	12.6%	16.9%	70.5%						
Aug	11.7%	16.0%	72.3%						
Sep	12.5%	18.1%	69.4%						
Oct	13.0%	19.8%	67.2%						
Nov	13.2%	19.0%	67.8%						
Dec	11.7%	16.8%	71.5%						
Annual	12.9%	17.0%	70.1%	12.0%	18.6%	69.4%	(0.8%)	1.6%	(0.7%)

Day-Ahead Load and Spot Market

Table 2-85 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2009 to June 30, 2010 (See 2009 SOM, Table 2-92)

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.4%	13.7%	81.9%	4.5%	17.8%	77.7%	0.1%	4.1%	(4.2%)
Feb	4.5%	12.3%	83.2%	4.5%	18.4%	77.1%	0.0%	6.0%	(6.1%)
Mar	4.3%	12.8%	82.9%	4.7%	18.4%	76.9%	0.3%	5.7%	(6.0%)
Apr	4.4%	13.8%	81.7%	4.8%	19.1%	76.1%	0.4%	5.3%	(5.6%)
May	4.6%	15.6%	79.8%	6.5%	19.0%	74.5%	1.9%	3.4%	(5.3%)
Jun	4.7%	13.9%	81.4%	4.6%	18.6%	76.8%	(0.1%)	4.7%	(4.7%)
Jul	5.6%	16.0%	78.4%						
Aug	5.2%	15.3%	79.5%						
Sep	4.8%	16.1%	79.2%						
Oct	5.0%	17.8%	77.2%						
Nov	5.8%	15.9%	78.3%						
Dec	5.2%	15.6%	79.2%						
Annual	4.9%	14.9%	80.2%	4.9%	18.5%	76.6%	0.0%	3.6%	(3.7%)

Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-86 Overview of Demand Side Programs (See 2009 SOM, Table 2-93)

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Voluntary Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for mandatory curtailments.	Energy payment based on LMP less generation component of retail rate. Energy payment for hours of voluntary curtailment.

Participation

Economic Program

Table 2-87 Economic Program registration on peak load days: Calendar years 2002 to 2009 and January through June 2010 (See 2009 SOM, Table 2-94)

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
03-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
02-Aug-06	253	1,100.7
08-Aug-07	2,897	2,498.0
09-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
23-Jun-10	727	1,891.5

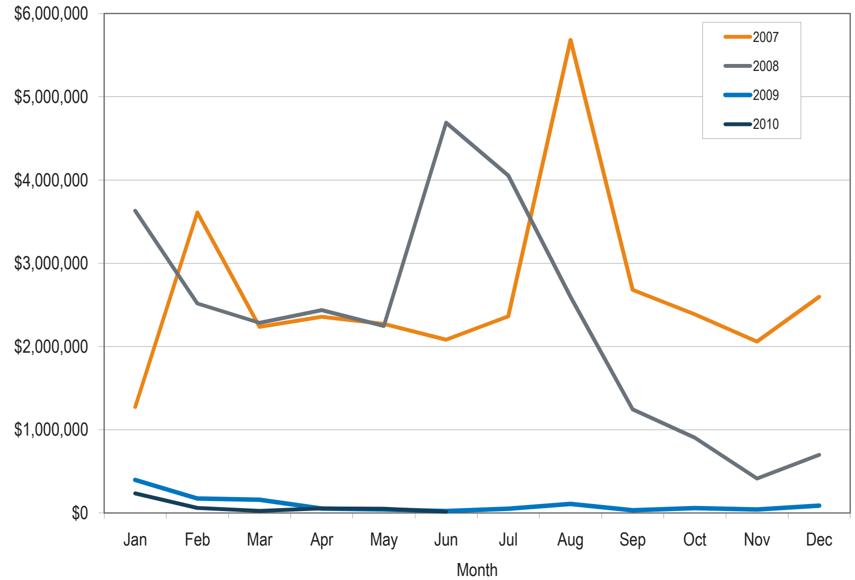
Table 2-88 Economic Program registrations on the last day of the month: January 2007 through June 2010 (See 2009 SOM, Table 2-95)

	2007		2008		2009		2010	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303	1,841	2,623
Feb	953	1,567	4,902	2,961	4,869	3,219	1,842	2,624
Mar	959	1,578	4,972	3,012	4,867	3,227	1,845	2,623
Apr	980	1,648	5,016	3,197	2,582	3,242	1,849	2,016
May	996	3,674	5,069	3,588	1,250	2,860	1,875	2,045
Jun	2,490	2,168	3,112	3,014	1,265	2,461	813	1,025
Jul	2,872	2,459	4,542	3,165	1,265	2,445		
Aug	2,911	2,582	4,815	3,232	1,653	2,650		
Sep	4,868	2,915	4,836	3,263	1,879	2,727		
Oct	4,873	2,880	4,846	3,266	1,875	2,730		
Nov	4,897	2,948	4,851	3,271	1,874	2,730		
Dec	4,898	2,944	4,851	3,290	1,853	2,627		
Avg.	2,684	2,408	4,727	3,185	2,508	2,852		

Table 2-89 Distinct registrations and sites in the Economic Program: June 23, 2010[8] (See 2009 SOM, Table 2-96)

	Registrations	Sites	MW
AECO	33	39	16.4
AEP	43	43	46.6
AP	37	39	148.9
BGE	58	70	467.7
ComEd	66	67	107.9
DAY	7	7	10.1
DLCO	76	76	171.1
Dominion	28	38	97.6
DPL	26	26	65.1
JCPL	37	72	120.6
Met-Ed	33	33	41.4
PECO	116	144	151.6
PENELEC	12	12	6.7
Pepco	12	13	18.2
PPL	97	104	122.8
PSEG	45	119	298.4
RECO	1	1	0.3
Total	727	903	1,891.5

Figure 2-25 Economic Program payments: Calendar years 2007[9] through 2009 and January through June 2010[10] (See 2009 SOM, Figure 2-24)



8 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, "Sites", reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

9 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 2-25 do not include these incentive payments.

10 June 2010 credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve settlements, which could account for a maximum of approximately 74 calendar days.

Table 2-90 PJM Economic Program by zonal reduction: January through June 2010 (See 2009 SOM, Table 2-99)

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO							0	$25	3	0	$25	3
AEP										0	$0	0
AP	2,088	$29,627	588				44	$5,780	22	2,132	$35,406	610
BGE										0	$0	0
ComEd	34	$1,166	37				518	$12,672	324	552	$13,838	361
DAY												
DLCO												
Dominion	3,257	$208,841	153	499	$7,714	76	314	$17,812	166	4,069	$234,367	395
DPL										0	$0	0
JCPL							11	$779	28	11	$779	28
Met-Ed	2	$16	8							2	$16	8
PECO	6,434	$137,603	7,583				105	$9,187	490	6,539	$146,791	8,073
PENELEC							3	$273	14	3	$273	14
Pepco							12	$453	63	12	$453	63
PPL	390	$8,686	310				32	$2,286	85	422	$10,972	395
PSEG										0	$0	0
RECO										0	$0	0
Total	12,204	$385,939	8,679	499	$7,714	76	1,039	$49,267	1,195	13,742	$442,919	9,950
Max	6,434	$208,841	7,583	499	$7,714	76	518	$17,812	490	6,539	$234,367	8,073
Avg	2,034	$64,323	1,447	499	$7,714	76	115	$5,474	133	916	$29,528	663

Table 2-91 Settlement days submitted by month in the Economic Program: January 2007 through June 2010 (See 2009 SOM, Table 2-100)

Month	2007	2008	2009	2010
Jan	937	2,916	1,264	1,423
Feb	1,170	2,811	654	546
Mar	1,255	2,818	574	411
Apr	1,540	3,406	337	338
May	1,649	3,336	918	974
Jun	1,856	3,184	2,727	1,603
Jul	2,534	3,339	2,879	
Aug	3,962	3,848	3,760	
Sep	3,388	3,264	2,570	
Oct	3,508	1,977	2,361	
Nov	2,842	1,105	2,321	
Dec	2,675	986	1,240	
Total	26,423	32,990	21,605	5,295

Table 2-92 Distinct customers and CSPs submitting settlements in the Economic Program by month: January 2007 through June 2010 (See 2009 SOM, Table 2-101)

	2007		2008		2009		2010	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	11	72	13	261	17	257	11	162
Feb	10	89	13	243	12	129	9	92
Mar	9	87	11	216	11	149	7	124
Apr	11	98	12	208	9	76	5	77
May	12	109	12	233	9	201	19	440
Jun	12	195	17	317	20	231	22	533
Jul	15	259	16	295	21	183		
Aug	19	321	17	306	15	400		
Sep	15	279	17	312	11	181		
Oct	11	245	13	226	11	93		
Nov	10	204	14	208	9	143		
Dec	11	243	13	193	10	160		
Total Distinct Active	21	405	24	522	25	747	22	533

Table 2-93 Hourly distribution of Economic Program MWh reductions and credits: January through June 2010 (See 2009 SOM, Table 2-102)

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	51	0.37%	51	0.37%	$635	0.14%	$635	0.14%
2	58	0.42%	109	0.79%	$639	0.14%	$1,274	0.29%
3	88	0.64%	197	1.43%	$1,133	0.26%	$2,407	0.54%
4	106	0.77%	303	2.21%	$2,451	0.55%	$4,858	1.10%
5	97	0.71%	401	2.92%	$1,182	0.27%	$6,040	1.36%
6	96	0.70%	497	3.61%	$1,328	0.30%	$7,367	1.66%
7	636	4.63%	1,132	8.24%	$34,516	7.79%	$41,883	9.46%
8	1,139	8.29%	2,271	16.53%	$73,874	16.68%	$115,757	26.14%
9	1,101	8.01%	3,372	24.54%	$40,587	9.16%	$156,344	35.30%
10	784	5.70%	4,156	30.24%	$23,970	5.41%	$180,314	40.71%
11	636	4.62%	4,791	34.86%	$15,223	3.44%	$195,537	44.15%
12	623	4.53%	5,414	39.39%	$13,217	2.98%	$208,754	47.13%
13	584	4.25%	5,998	43.65%	$13,685	3.09%	$222,439	50.22%
14	593	4.31%	6,590	47.96%	$13,746	3.10%	$236,185	53.32%
15	655	4.77%	7,245	52.72%	$11,293	2.55%	$247,477	55.87%
16	574	4.18%	7,819	56.90%	$13,034	2.94%	$260,511	58.82%
17	701	5.10%	8,520	62.00%	$23,532	5.31%	$284,043	64.13%
18	884	6.43%	9,405	68.44%	$28,037	6.33%	$312,080	70.46%
19	1,111	8.08%	10,515	76.52%	$46,970	10.60%	$359,051	81.06%
20	1,031	7.50%	11,546	84.02%	$32,183	7.27%	$391,234	88.33%
21	765	5.57%	12,311	89.59%	$27,581	6.23%	$418,815	94.56%
22	614	4.47%	12,925	94.06%	$14,329	3.24%	$433,144	97.79%
23	463	3.37%	13,388	97.43%	$5,736	1.30%	$438,880	99.09%
24	354	2.57%	13,742	100.00%	$4,040	0.91%	$442,919	100.00%

Table 2-94 Distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through June 2010 (See 2009 SOM, Table 2-103)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	32	0.24%	32	0.24%	$5	0.00%	$5	0.00%
$25 to $50	7,163	52.12%	7,195	52.36%	$82,207	18.56%	$82,212	18.56%
$50 to $75	2,723	19.81%	9,918	72.17%	$70,555	15.93%	$152,766	34.49%
$75 to $100	1,197	8.71%	11,115	80.88%	$53,208	12.01%	$205,975	46.50%
$100 to $125	984	7.16%	12,099	88.04%	$59,084	13.34%	$265,059	59.84%
$125 to $150	697	5.07%	12,796	93.11%	$44,175	9.97%	$309,233	69.82%
$150 to $200	574	4.18%	13,370	97.29%	$60,047	13.56%	$369,281	83.37%
$200 to $250	203	1.48%	13,573	98.77%	$35,290	7.97%	$404,570	91.34%
$250 to $300	83	0.60%	13,656	99.38%	$16,085	3.63%	$420,655	94.97%
> $300	86	0.62%	13,742	100.00%	$22,264	5.03%	$442,919	100.00%

Emergency Program

Table 2-95 Registered sites and MW in the Emergency Program[11] (By zone and option): June 23, 2010 (See 2009 SOM, Table 2-104)

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	102	58.5	8	18.0
AEP	0	0.0	688	1,039.1	169	805.4
AP	0	0.0	672	612.0	105	180.5
BGE	0	0.0	441	758.1	28	79.3
ComEd	0	0.0	899	949.9	585	514.6
DAY	0	0.0	163	135.0	17	72.2
DLCO	0	0.0	263	158.3	13	46.4
Dominion	0	0.0	503	919.9	34	86.2
DPL	0	0.0	174	140.8	19	37.7
JCPL	0	0.0	206	161.0	19	17.5
Met-Ed	0	0.0	196	149.4	36	38.3
PECO	0	0.0	455	312.1	191	113.9
PENELEC	0	0.0	304	297.0	31	15.1
Pepco	0	0.0	265	177.8	30	38.8
PPL	0	0.0	643	671.2	87	60.1
PSEG	0	0.0	406	334.3	126	52.4
RECO	0	0.0	3	1.7	0	0.0
Total	0	0.0	6,383	6,876.0	1,498	2,176.4

Table 2-96 Registered MW in the Load Management Program by program type: Delivery years 2007/2008 through 2010/2011 (See 2009 SOM, Table 2-105)

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,020.5	6,273.8	7,294.3
2010/2011	1,070.0	7,982.4	9,052.4

11 Table 2-97 shows registered sites and MW in the Emergency Program as of June 23, 2010, the peak load day through the first six months of 2010. As all resources are registered in either the Capacity Only or Full options, all resources in the Emergency Program are considered RPM Resources participating in the Load Management (LM) Program and Table 2-98 reflects the same participation. Registered sites and MW remain constant in the LM Program through delivery years. For more information on LM Program participation and testing, see the *2009 State of the Market Report for PJM*, Volume II, Section 2 – Energy Market, Part 1: <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2-sec2.pdf>.

Table 2-97 Zonal monthly capacity credits: January 1, 2010 through June 30, 2010 (See 2009 SOM, Table 2-106)

Zone	January	February	March	April	May	June	Total
AECO	$538,827	$486,683	$387,589	$521,446	$538,827	$498,630	$2,972,002
AEP	$3,871,619	$3,496,946	$3,871,619	$3,746,728	$3,871,619	$7,469,753	$26,328,283
APS	$3,380,342	$3,053,212	$3,082,016	$3,271,298	$3,380,342	$4,134,986	$20,302,196
BGE	$4,971,814	$4,490,671	$4,613,517	$4,811,433	$4,971,814	$4,877,253	$28,736,503
ComEd	$4,423,355	$3,995,288	$4,357,876	$4,280,666	$4,423,355	$7,893,843	$29,374,382
DAY	$667,966	$603,324	$667,966	$646,419	$667,966	$1,114,399	$4,368,041
DLCO	$387,642	$350,129	$387,642	$375,138	$387,642	$1,082,462	$2,970,655
Dominion	$1,655,820	$1,495,580	$1,655,820	$1,602,407	$1,655,820	$5,271,768	$13,337,216
DPL	$1,117,919	$1,009,733	$1,004,045	$1,081,857	$1,117,919	$1,053,129	$6,384,600
JCPL	$1,374,149	$1,241,167	$897,896	$1,329,822	$1,374,149	$1,259,066	$7,476,248
Met-Ed	$1,357,392	$1,226,031	$1,357,392	$1,313,605	$1,357,392	$1,166,215	$7,778,027
PECO	$2,717,550	$2,454,561	$2,120,899	$2,629,887	$2,717,550	$2,735,060	$15,375,506
PENELEC	$1,325,705	$1,197,411	$1,325,705	$1,282,941	$1,325,705	$1,768,655	$8,226,123
Pepco	$1,161,239	$1,048,861	$814,714	$1,123,780	$1,161,239	$1,265,186	$6,575,019
PPL	$3,583,739	$3,236,926	$3,617,545	$3,468,134	$3,583,739	$3,982,417	$21,472,500
PSEG	$2,266,920	$2,047,540	$1,777,619	$2,193,793	$2,266,920	$2,454,980	$13,007,772
RECO	$24,425	$22,061	$18,494	$23,637	$24,425	$8,967	$122,008
Total	$34,826,423	$31,456,124	$31,958,354	$33,702,990	$34,826,423	$48,036,768	$214,807,081

Table 2-98 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007/2008 through 2013/2014 (See 2009 SOM, Table 2-107)

Planning Year	DR Offered in BRA	DR Cleared in BRA
2007/2008	123.5	123.5
2008/2009	691.9	518.5
2009/2010	906.9	865.2
2010/2011	935.6	908.1
2011/2012	1,597.3	1,319.5
2012/2013	9,535.4	6,824.1
2013/2014	12,528.7	8,977.4

SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for the first six months of 2010. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, 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.

Overview

Net Revenue

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

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

- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve PJM markets. Net revenue quantifies the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources when there is a market based need, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  In 2009, total net revenues were not adequate to cover total fixed costs for a new entrant combustion turbine (CT), combined cycle (CC) or coal plant (CP) in any zone. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs, reflecting their greater reliance on capacity market revenues in a year with reduced energy market revenues.

  In the first six months of 2010, total net revenues were generally higher compared to the same period in 2009. The changes in total net revenues by technology type are the result of changes in energy revenues, resulting from energy prices, and changes in capacity revenues, resulting from prior RPM auctions. In general, energy revenues are a larger proportion of total net revenues for CPs and CCs while capacity revenues are a larger proportion of total net revenues for CTs.

  For the new entrant CT, fourteen zones had higher total net revenue in the first half of 2010 compared to the same period in 2009, while AEP, ComEd and DAY had lower total net revenues. (Table 3-8.) For the new entrant CT, all zones except AP had higher energy net revenue. The six zones that were part of the MAAC+AP Locational Delivery Area (LDA) for the 2009/2010 delivery year, which previously cleared in the EMAAC LDA, had slightly higher capacity revenues. The two zones that were part of the SWMAAC LDA and the five zones that cleared in the unconstrained RTO LDA for the 2009/2010 delivery year had lower capacity revenues. The AP, Met-Ed, PENELEC and PPL zones, which had cleared with unconstrained RTO LDA in the 2008/2009 delivery year, had significantly higher capacity revenues associated with the constrained MAAC+AP LDA. For AP, higher capacity revenues more than offset lower energy net revenues.

  For the new entrant CC, fourteen zones had higher total net revenue in the first half of 2010 compared to the same period in 2009, while AEP, ComEd and DAY had lower total net revenues. (Table 3-10.) For the new entrant CC, AP, ComEd and PENELEC had a decrease in energy net revenue. For AP and PENELEC, higher capacity revenues more than offset this decrease. For AEP and DAY, slightly higher energy net revenues were more than offset by the decrease in capacity revenues.

For the new entrant coal plant (CP), all seventeen zones had higher total net revenue in the first half of 2010 compared to the same period in 2009. (Table 3-12.) For the CP, all zones showed an increase in energy net revenues. For the two SWMAAC zones and five RTO zones, higher energy net revenue more than offset decreases in capacity revenues.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through June 30, 2010, PJM installed capacity resources fell slightly from 167,853.8 MW on January 1 to 166,621.8 MW on June 30, a decrease of 1,232.0 MW or 0.7 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of June 30, 2010, 40.7 percent was coal; 29.1 percent was natural gas; 18.4 percent was nuclear; 6.4 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was solid waste, and 0.3 percent was wind.

- **Generation Fuel Mix.** During the first six months of 2010, coal provided 50.8 percent, nuclear 35.6 percent, gas 9.1 percent, oil 0.2 percent, hydroelectric 2.3 percent, solid waste 0.8 percent and wind 1.2 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.

Scarcity

- **Scarcity Pricing Events in the first six months of 2010.** PJM did not declare a scarcity event in the first six months of 2010.

  In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity.

- **Modifications to Scarcity Pricing.** PJM's scarcity pricing rules need refinement.

  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. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM.

  The essential components of a new approach to scarcity pricing include: reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch; an appropriate operating reserve target, e.g. 10 minute synchronized reserves; accurate measurement of the operating reserve levels used as a scarcity trigger; an accurate and effective scarcity pricing revenue true up mechanism; a rule governing the recall of the energy from capacity resources during scarcity events; and maintaining local market power mitigation mechanisms.

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, operating reserve payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those participants paying the operating reserve charges that equal these credits, 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 2010.** The level of operating reserve credits and corresponding charges increased in the first six months of 2010 by 44.7 percent compared to the first six months of 2009. Most of this increase occurred in the second quarter of 2010. The level of operating reserve credits in the first quarter of 2010 increased by only 9.0 percent compared to the first quarter of 2009. The increase in total operating reserve credits was comprised of a 1.8 percent, or $826,461, increase in the amount of day-ahead credits, an 80.7 percent, or $1,856,299, decrease in synchronous condensing credits, and a 63.5 percent, or $76,634,160, increase in balancing credits. The increase in balancing credits can primarily be attributed to a large increase in Eastern reliability credits. Eastern reliability credits accounted for $290,150 in the first quarter of 2010 and $28,161,278 in the second quarter of 2010.

- **New Operating Reserve Rules.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. The MMU calculated the impact of the new operating reserve rules in three areas.

  The rule changes allocated an increased proportion of balancing operating reserve credits to real-time load and exports. The purpose of this rule change was to reallocate a portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, defined as real-time load and exports. This rule change had a significant impact in the second quarter of 2010. The new operating reserve rules resulted in an increase of $54,057,630 in charges assigned to real-time load and exports for the first six months of 2010. These increases were matched by a decrease of $29,315,256 in charges to demand deviations, a decrease of $16,159,640 in charges to supply deviations, and a decrease of $8,582,734 in charges to generator deviations.

  The rule changes resulted in a reduced allocation of charges to deviations, which reduced operating reserve payments assigned to virtual market activity. The net result is that virtual offers and bids paid $18,106,662 less in operating reserve charges as a result of the change in rules than they would have paid under the old rules. These charges were paid by real time load and exports.

  The rule changes included the introduction of segmented make whole payments, which results in a calculation of operating reserve credits for periods shorter than the 24 hours used under the old rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $6,257,231, or 4.5 percent, higher for the first six months of 2010 than they would have been under the old rules. The most significant difference since the new rule went into effect was for June 2010, when the increase in payments due to the rule change was $2,602,710.

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.

The second quarter of 2010 showed a reversal of trends noted in the first quarter of 2010 when compared to the same time period in the prior year. In the second quarter of 2010, energy market revenues were generally higher for combustion turbines and combined cycles, both using natural gas, as energy market prices in the second quarter increased more than the average delivered price of natural gas in most zones. Energy market net revenues for the CP were substantially higher in all zones as a result of higher energy market prices in the second quarter.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. Several zones had more high demand days in the second quarter of 2010 compared to 2009. The average on peak LMP for Dominion and DLCO increased by 14.6 and 15.8 percent. As a result, while the average increase in energy net revenue for a new entrant CT was 99 percent, the Dominion and DLCO zones show increases of 142 and 315 percent respectively.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the Capacity Market provides a significant stream of revenue that contributes to the recovery of total costs for existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The Capacity Market is also a significant source of net revenue to cover the fixed costs of investing in new peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when there is a mismatch between the energy net revenues used as the offset in determining Capacity Market prices and actual energy net revenues, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs.

Coal plants (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. When less efficient coal units are on the margin, net revenues are higher for more efficient coal units. Coal units also receive higher net revenue when load following and peaking gas-fired units set price. For the first six months of 2010, particularly in May and June, CCs and CTs ran more often, which increased the net revenue received by coal plants.

Net Revenue

Capacity Market Net Revenue

Table 3-1 2010 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2010 (See 2009 SOM, Table 3-3)

	Delivery Year 2009/2010			Delivery Year 2010/2011			RPM Revenue 2010
Zone	LDA	$/MW-Day	$/MW in 2010	LDA	$/MW-Day	$/MW in 2010	(Jan - Dec) $/MW
AECO	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
AEP	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
AP	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
BGE	SWMAAC	$237.33	$35,837		$174.29	$37,298	$73,135
ComEd	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
DAY	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
DLCO	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
Dominion	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
DPL	MAAC+APS	$191.32	$28,889	DPL-SOUTH	$186.12	$39,830	$68,719
JCPL	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
Met-Ed	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PECO	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PENELEC	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
Pepco	SWMAAC	$237.33	$35,837		$174.29	$37,298	$73,135
PPL	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PSEG	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
RECO	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PJM	NA	$138.46	$20,907	NA	$174.42	$37,327	$58,234

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-4)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$28,208	$28,889	2%
AEP	$19,961	$15,408	(23%)
AP	$22,640	$28,889	28%
BGE	$38,847	$35,837	(8%)
ComEd	$19,961	$15,408	(23%)
DAY	$19,961	$15,408	(23%)
DLCO	$19,961	$15,408	(23%)
Dominion	$19,961	$15,408	(23%)
DPL	$28,208	$28,889	2%
JCPL	$28,208	$28,889	2%
Met-Ed	$22,640	$28,889	28%
PECO	$28,208	$28,889	2%
PENELEC	$22,640	$28,889	28%
Pepco	$38,847	$35,837	(8%)
PPL	$22,640	$28,889	28%
PSEG	$28,208	$28,889	2%
RECO	$28,208	$28,889	2%
PJM	$22,965	$20,907	(9%)

New Entrant Net Revenues

Table 3-3 Average delivered fuel price in PJM[1] (Dollars per MBtu): January through June 2009 and 2010 (See 2009 SOM, Table 3-5)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
Natural Gas	$4.95	$5.32	7%
Delivered Coal	$3.26	$2.50	(23%)

Table 3-4 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[2] : Net revenue for January through June 2009 and 2010 (See 2009 SOM, Table 3-6)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$5,450	$12,236	125%
AEP	$2,313	$2,410	4%
AP	$8,213	$7,779	(5%)
BGE	$7,346	$17,441	137%
ComEd	$1,595	$1,696	6%
DAY	$1,941	$2,317	19%
DLCO	$1,633	$6,771	315%
Dominion	$7,709	$18,632	142%
DPL	$6,784	$12,676	87%
JCPL	$6,199	$11,522	86%
Met-Ed	$5,416	$11,068	104%
PECO	$4,733	$11,051	133%
PENELEC	$3,596	$4,055	13%
Pepco	$11,729	$22,484	92%
PPL	$4,666	$9,512	104%
PSEG	$4,371	$11,752	169%
RECO	$3,626	$10,219	182%
PJM	$5,136	$10,213	99%

1 The average delivered fuel prices shown in Table 3-3 are included for illustrative purposes, and represent the simple average of several indices for various delivery points throughout the PJM footprint.

2 The energy net revenues presented for "PJM" for the periods January through June 2009 and 2010 in this section represent the simple average of all zonal energy net revenues. Similarly, the total net revenues presented for "PJM" represent the simple average energy net revenue.

Table 3-5 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for January through June 2009 and 2010 (See 2009 SOM, Table 3-7)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$25,588	$36,518	43%
AEP	$14,814	$15,284	3%
AP	$30,922	$28,962	(6%)
BGE	$28,065	$44,508	59%
ComEd	$12,192	$11,478	(6%)
DAY	$14,505	$15,586	7%
DLCO	$13,010	$19,160	47%
Dominion	$29,532	$44,704	51%
DPL	$27,532	$37,913	38%
JCPL	$27,643	$36,167	31%
Met-Ed	$23,875	$33,683	41%
PECO	$23,309	$34,471	48%
PENELEC	$22,215	$21,127	(5%)
Pepco	$37,313	$53,216	43%
PPL	$22,156	$30,948	40%
PSEG	$24,641	$36,705	49%
RECO	$21,913	$32,078	46%
PJM	$23,484	$31,324	33%

Table 3-6 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for January through June 2009 and 2010 (See 2009 SOM, Table 3-8)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$55,686	$88,154	58%
AEP	$17,349	$54,788	216%
AP	$35,617	$68,308	92%
BGE	$32,123	$94,799	195%
ComEd	$26,197	$50,436	93%
DAY	$22,324	$43,901	97%
DLCO	$18,800	$50,387	168%
Dominion	$34,847	$85,647	146%
DPL	$28,682	$69,366	142%
JCPL	$51,802	$83,895	62%
Met-Ed	$43,014	$77,670	81%
PECO	$51,543	$84,385	64%
PENELEC	$49,034	$60,925	24%
Pepco	$46,748	$93,005	99%
PPL	$49,206	$79,420	61%
PSEG	$69,576	$88,584	27%
RECO	$49,545	$80,786	63%
PJM	$40,123	$73,792	84%

New Entrant Combustion Turbine

Table 3-7 Real-time PJM average net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through June 2010 (See 2009 SOM, Table 3-9)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
Energy	$5,136	$10,213	99%
Capacity	$20,466	$18,849	(8%)
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,199	$1,199	0%
Total	$26,801	$30,261	13%

Table 3-8 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-10)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$31,788	$39,481	24%
AEP	$21,301	$17,500	(18%)
AP	$29,588	$35,023	18%
BGE	$43,163	$50,948	18%
ComEd	$20,582	$16,786	(18%)
DAY	$20,929	$17,407	(17%)
DLCO	$20,621	$21,861	6%
Dominion	$26,696	$33,722	26%
DPL	$33,121	$39,921	21%
JCPL	$32,536	$38,766	19%
Met-Ed	$26,790	$38,312	43%
PECO	$31,071	$38,295	23%
PENELEC	$24,971	$31,299	25%
Pepco	$47,547	$55,992	18%
PPL	$26,041	$36,756	41%
PSEG	$30,709	$38,997	27%
RECO	$29,964	$37,464	25%
PJM	$26,801	$30,261	13%

New Entrant Combined Cycle

Table 3-9 Real-time PJM average net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through June 2010 (See 2009 SOM, Table 3-11)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
Energy	$23,484	$31,324	33%
Capacity	$22,186	$20,111	(9%)
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,599	$1,599	0%
Total	$47,269	$53,034	12%

Table 3-10 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-12)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$54,438	$65,906	21%
AEP	$35,697	$31,705	(11%)
AP	$54,393	$58,350	7%
BGE	$67,192	$80,579	20%
ComEd	$33,075	$27,898	(16%)
DAY	$35,388	$32,006	(10%)
DLCO	$33,893	$35,581	5%
Dominion	$50,415	$61,124	21%
DPL	$56,382	$67,301	19%
JCPL	$56,494	$65,555	16%
Met-Ed	$47,345	$63,071	33%
PECO	$52,159	$63,859	22%
PENELEC	$45,685	$50,515	11%
Pepco	$76,441	$89,287	17%
PPL	$45,626	$60,336	32%
PSEG	$53,491	$66,092	24%
RECO	$50,763	$61,466	21%
PJM	$47,269	$53,034	12%

New Entrant Coal Plant

Table 3-11 Real-time PJM average net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through June 2010 (See 2009 SOM, Table 3-13)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
Energy	$40,123	$73,792	84%
Capacity	$20,705	$18,960	(8%)
Synchronized	$0	$0	0%
Regulation	$137	$58	(58%)
Reactive	$892	$892	0%
Total	$61,857	$93,701	51%

Table 3-12 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-14)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$82,208	$115,515	41%
AEP	$36,395	$69,937	92%
AP	$57,064	$95,676	68%
BGE	$68,139	$128,463	89%
ComEd	$45,593	$65,562	44%
DAY	$41,706	$58,928	41%
DLCO	$37,864	$65,495	73%
Dominion	$53,855	$100,698	87%
DPL	$55,093	$96,597	75%
JCPL	$78,299	$111,247	42%
Met-Ed	$64,466	$105,003	63%
PECO	$78,050	$111,744	43%
PENELEC	$71,059	$88,283	24%
Pepco	$82,825	$126,633	53%
PPL	$70,683	$106,781	51%
PSEG	$96,634	$115,938	20%
RECO	$76,028	$108,144	42%
PJM	$61,857	$93,701	51%

New Entrant Day-Ahead Net Revenues

Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-15)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$2,438	$5,634	131%
AEP	$739	$597	(19%)
AP	$3,314	$3,432	4%
BGE	$3,338	$9,478	184%
ComEd	$239	$532	123%
DAY	$350	$613	75%
DLCO	$224	$2,201	884%
Dominion	$4,073	$10,371	155%
DPL	$3,066	$4,966	62%
JCPL	$2,106	$4,774	127%
Met-Ed	$1,926	$4,955	157%
PECO	$2,030	$4,605	127%
PENELEC	$1,967	$1,440	(27%)
Pepco	$7,911	$15,602	97%
PPL	$1,775	$3,369	90%
PSEG	$1,378	$4,481	225%
RECO	$950	$4,080	329%
PJM	$2,225	$4,772	114%

Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-16)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$23,204	$32,703	41%
AEP	$10,796	$12,695	18%
AP	$24,872	$27,062	9%
BGE	$25,069	$41,715	66%
ComEd	$6,900	$8,317	21%
DAY	$9,212	$12,124	32%
DLCO	$7,841	$16,556	111%
Dominion	$27,288	$41,764	53%
DPL	$24,570	$32,782	33%
JCPL	$24,738	$33,324	35%
Met-Ed	$20,553	$30,641	49%
PECO	$21,541	$31,580	47%
PENELEC	$19,402	$22,077	14%
Pepco	$35,424	$53,078	50%
PPL	$19,487	$27,485	41%
PSEG	$22,143	$32,240	46%
RECO	$18,957	$28,965	53%
PJM	$20,117	$28,536	42%

Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-17)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$57,249	$91,588	60%
AEP	$14,442	$55,505	284%
AP	$31,212	$70,267	125%
BGE	$33,849	$99,933	195%
ComEd	$23,685	$50,824	115%
DAY	$18,754	$43,193	130%
DLCO	$14,184	$51,144	261%
Dominion	$34,963	$89,659	156%
DPL	$28,992	$71,438	146%
JCPL	$52,416	$87,906	68%
Met-Ed	$43,004	$81,730	90%
PECO	$53,977	$88,737	64%
PENELEC	$49,787	$67,261	35%
Pepco	$48,096	$99,139	106%
PPL	$50,190	$83,421	66%
PSEG	$72,594	$91,826	26%
RECO	$50,273	$87,064	73%
PJM	$39,863	$77,096	93%

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through June 2010 (See 2009 SOM, Table 3-18)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,183	62%
2008	$12,442	$6,623	$5,819	47%
2009	$5,113	$1,966	$3,148	62%
2010 (Jan - Jun)	$10,213	$4,772	$5,441	53%

Table 3-17 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through June 2010 (See 2009 SOM, Table 3-19)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,631	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,196	20%
2006	$44,692	$31,670	$13,023	29%
2007	$66,616	$44,434	$22,183	33%
2008	$62,039	$47,342	$14,697	24%
2009	$31,581	$28,360	$3,221	10%
2010 (Jan - Jun)	$31,324	$28,536	$2,788	9%

Table 3-18 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through June 2010 (See 2009 SOM, Table 3-20)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,159)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,374)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,571	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,267	3%
2009	$49,022	$45,844	$3,178	6%
2010 (Jan - Jun)	$73,792	$77,096	($3,305)	(4%)

Net Revenue Adequacy

Table 3-19 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)) (See 2009 SOM, Table 3-21)

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

Table 3-20 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-23)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$31,788	$39,481	$128,705	25%	31%
AEP	$21,301	$17,500	$128,705	17%	14%
AP	$29,588	$35,023	$128,705	23%	27%
BGE	$43,163	$50,948	$128,705	34%	40%
ComEd	$20,582	$16,786	$128,705	16%	13%
DAY	$20,929	$17,407	$128,705	16%	14%
DLCO	$20,621	$21,861	$128,705	16%	17%
Dominion	$26,696	$33,722	$128,705	21%	26%
DPL	$33,121	$39,921	$128,705	26%	31%
JCPL	$32,536	$38,766	$128,705	25%	30%
Met-Ed	$26,790	$38,312	$128,705	21%	30%
PECO	$31,071	$38,295	$128,705	24%	30%
PENELEC	$24,971	$31,299	$128,705	19%	24%
Pepco	$47,547	$55,992	$128,705	37%	44%
PPL	$26,041	$36,756	$128,705	20%	29%
PSEG	$30,709	$38,997	$128,705	24%	30%
RECO	$29,964	$37,464	$128,705	23%	29%
PJM	$26,801	$30,261	$128,705	21%	24%

Figure 3-1 New entrant CT real-time 2009 and 2010 net revenue for January through June and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-3)

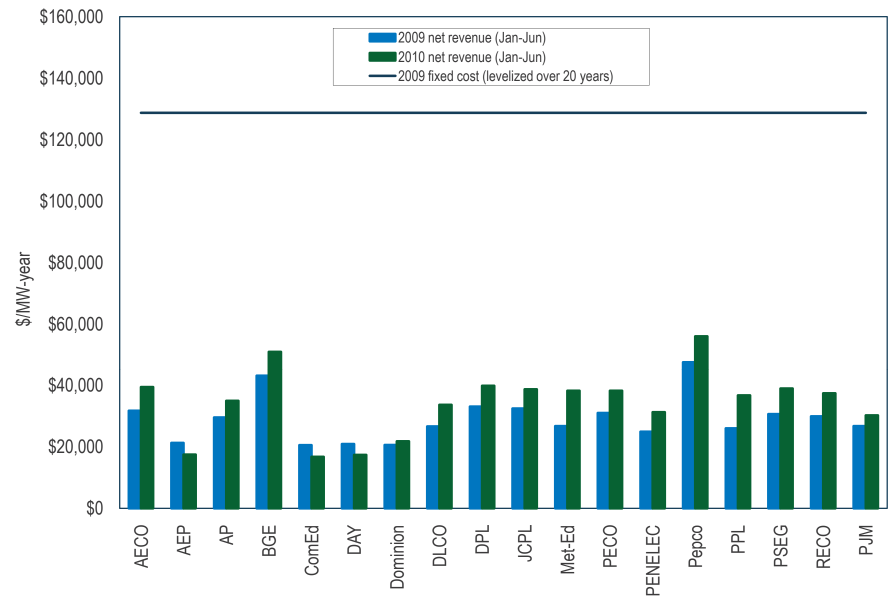


Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-25)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$54,438	$65,906	$173,174	31%	38%
AEP	$35,697	$31,705	$173,174	21%	18%
AP	$54,393	$58,350	$173,174	31%	34%
BGE	$67,192	$80,579	$173,174	39%	47%
ComEd	$33,075	$27,898	$173,174	19%	16%
DAY	$35,388	$32,006	$173,174	20%	18%
DLCO	$33,893	$35,581	$173,174	20%	21%
Dominion	$50,415	$61,124	$173,174	29%	35%
DPL	$56,382	$67,301	$173,174	33%	39%
JCPL	$56,494	$65,555	$173,174	33%	38%
Met-Ed	$47,345	$63,071	$173,174	27%	36%
PECO	$52,159	$63,859	$173,174	30%	37%
PENELEC	$45,685	$50,515	$173,174	26%	29%
Pepco	$76,441	$89,287	$173,174	44%	52%
PPL	$45,626	$60,336	$173,174	26%	35%
PSEG	$53,491	$66,092	$173,174	31%	38%
RECO	$50,763	$61,466	$173,174	29%	35%
PJM	$47,269	$53,034	$173,174	27%	31%

Figure 3-2 New entrant CC real-time 2009 and 2010 net revenue for January through June and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-5)

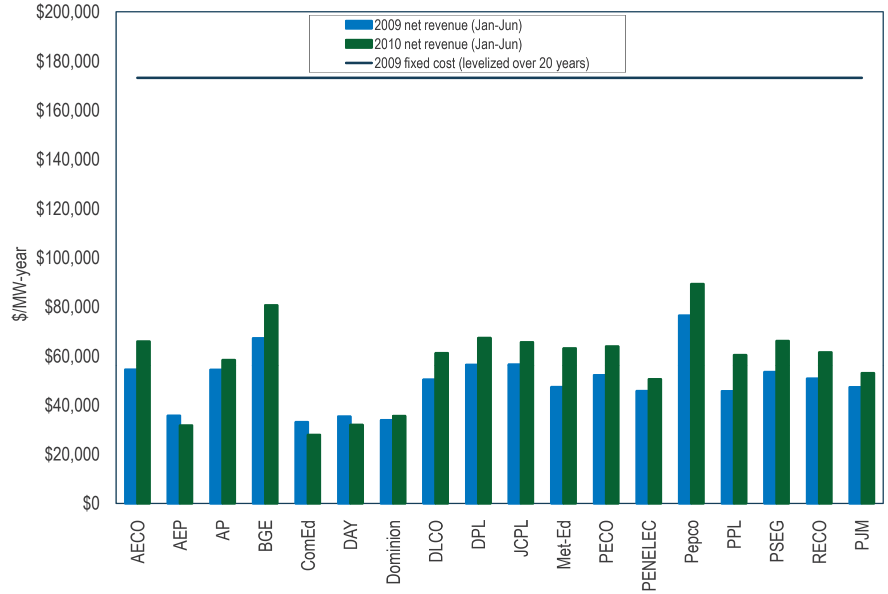
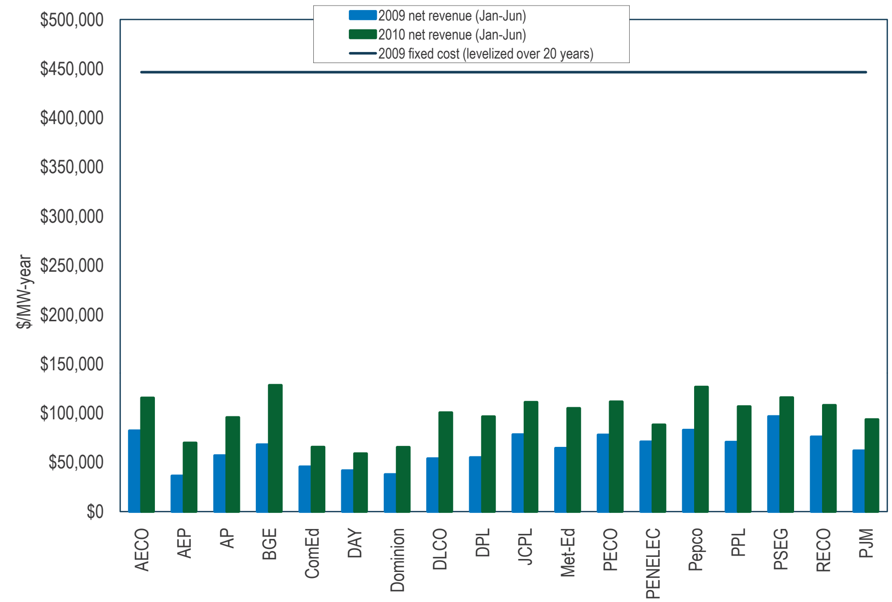


Table 3-22 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-27)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$82,208	$115,515	$446,550	18%	26%
AEP	$36,395	$69,937	$446,550	8%	16%
AP	$57,064	$95,676	$446,550	13%	21%
BGE	$68,139	$128,463	$446,550	15%	29%
ComEd	$45,593	$65,562	$446,550	10%	15%
DAY	$41,706	$58,928	$446,550	9%	13%
DLCO	$37,864	$65,495	$446,550	8%	15%
Dominion	$53,855	$100,698	$446,550	12%	23%
DPL	$55,093	$96,597	$446,550	12%	22%
JCPL	$78,299	$111,247	$446,550	18%	25%
Met-Ed	$64,466	$105,003	$446,550	14%	24%
PECO	$78,050	$111,744	$446,550	17%	25%
PENELEC	$71,059	$88,283	$446,550	16%	20%
Pepco	$82,825	$126,633	$446,550	19%	28%
PPL	$70,683	$106,781	$446,550	16%	24%
PSEG	$96,634	$115,938	$446,550	22%	26%
RECO	$76,028	$108,144	$446,550	17%	24%
PJM	$61,857	$93,701	$446,550	14%	21%

Figure 3-3 New entrant CP real-time 2009 and 2010 net revenue for January through June and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-7)



Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-23 PJM installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2010 (See 2009 SOM, Table 3-35)

	1-Jan-10		31-May-10		1-Jun-10		30-Jun-10	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	68,382.1	40.7%	68,155.5	40.7%	67,991.1	40.8%	67,858.1	40.7%
Gas	49,238.8	29.3%	48,991.4	29.3%	48,424.5	29.0%	48,426.5	29.1%
Hydroelectric	7,921.9	4.7%	7,923.5	4.7%	7,923.5	4.8%	7,923.5	4.8%
Nuclear	30,611.9	18.2%	30,599.3	18.3%	30,619.0	18.4%	30,619.0	18.4%
Oil	10,700.1	6.4%	10,649.4	6.4%	10,645.5	6.4%	10,645.5	6.4%
Solid waste	672.1	0.4%	672.1	0.4%	672.1	0.4%	668.1	0.4%
Wind	326.9	0.2%	409.5	0.2%	481.1	0.3%	481.1	0.3%
Total	167,853.8	100.0%	167,400.7	100.0%	166,756.8	100.0%	166,621.8	100.0%

Energy Production by Fuel Source

Table 3-24 PJM generation (By fuel source (GWh)): January through June 2010 (See 2009 SOM, Table 3-36)

	GWh	Percent
Coal	180,931.2	50.8%
Nuclear	126,789.7	35.6%
Gas	32,244.2	9.1%
Natural Gas	31,455.3	8.8%
Landfill Gas	788.7	0.2%
Biomass Gas	0.2	0.0%
Hydroelectric	8,146.2	2.3%
Wind	4,183.0	1.2%
Waste	3,020.1	0.8%
Solid Waste	2,325.0	0.7%
Miscellaneous	695.1	0.2%
Oil	875.5	0.2%
Heavy Oil	687.0	0.2%
Light Oil	175.0	0.0%
Diesel	10.3	0.0%
Kerosene	3.2	0.0%
Jet Oil	0.1	0.0%
Solar	2.1	0.0%
Battery	0.2	0.0%
Total	356,192.2	100.0%

Planned Generation Additions

Table 3-25 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through June 2010[3] (See 2009 SOM, Table 3-37)

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	15,228	(7,506)	(49)%
2011	15,873	17,356	1,483	9%
2012	11,053	12,579	1,526	12%
2013	6,350	7,506	1,156	15%
2014	13,439	12,474	(965)	(8)%
2015	3,091	2,958	(133)	(4)%
2016	950	1,350	400	30%
2017	1,640	1,640	0	0%
2018	1,594	3,194	1,600	50%
Total	76,725	74,286	(2,439)	(3)%

PJM Generation Queues

Table 3-26 Queue comparison (MW): June 30, 2010 vs. December 31, 2009 (See 2009 SOM, Table 3-38)

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	15,228	(7,506)	(49)%
2011	15,873	17,356	1,483	9%
2012	11,053	12,579	1,526	12%
2013	6,350	7,506	1,156	15%
2014	13,439	12,474	(965)	(8)%
2015	3,091	2,958	(133)	(4)%
2016	950	1,350	400	30%
2017	1,640	1,640	0	0%
2018	1,594	3,194	1,600	50%
Total	76,725	74,286	(2,439)	(3)%

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

Table 3-27 Capacity in PJM queues (MW): At June 30, 2010[4, 5] (See 2009 SOM, Table 3-39)

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	4,671	0	15,833	20,503
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	16,887	17,682
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	21,986	23,102
H Expired 31-Jan-02	0	603	100	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,738	3,841
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	128	100	2,416	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	0	3,978	4,482
N Expired 31-Jan-05	1,377	2,143	223	6,663	10,407
O Expired 31-Jul-05	1,978	1,048	444	4,104	7,574
P Expired 31-Jan-06	853	1,008	1,886	4,918	8,665
Q Expired 31-Jul-06	1,945	707	3,583	8,413	14,648
R Expired 31-Jan-07	5,511	648	708	15,974	22,840
S Expired 31-Jul-07	7,421	1,034	1,260	11,068	20,782
T Expired 31-Jan-08	12,886	397	299	10,979	24,560
U Expired 31-Jan-09	10,980	112	770	19,572	31,434
V Expired 31-Jan-10	13,639	3	128	2,996	16,766
W Expires 31-Jan-11	7,546	0	0	0	7,546

Table 3-28 Average project queue times: At June 30, 2010 (See 2009 SOM, Table 3-40)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	864	659	0	4,420
In-Service	737	620	0	3,287
Suspended	2,296	744	890	3,622
Under Construction	1,182	892	0	4,370
Withdrawn	503	503	0	3,186

4 The *2010 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..

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

Distribution of Units in the Queues

Table 3-29 Capacity additions in active or under-construction queues by control zone (MW): At June 30, 2010[6] (See 2009 SOM, Table 3-41)

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	15,228	(7,506)	(49)%
2011	15,873	17,356	1,483	9%
2012	11,053	12,579	1,526	12%
2013	6,350	7,506	1,156	15%
2014	13,439	12,474	(965)	(8)%
2015	3,091	2,958	(133)	(4)%
2016	950	1,350	400	30%
2017	1,640	1,640	0	0%
2018	1,594	3,194	1,600	50%
Total	76,725	74,286	(2,439)	(3)%

Table 3-30 Capacity additions in active or under-construction queues by LDA (MW): At June 30, 2010[7] (See 2009 SOM, Table 3-42)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	0	4,293	1,576	51	0	510	1,533	771	1,516	67	10,316
SWMAAC	0	2,025	230	6	0	1,640	0	132	0	25	4,058
WMAAC	40	650	201	53	175	1,624	120	133	1,279	16	4,289
RTO	22	7,184	3,546	135	350	2,818	553	4,802	36,206	8	55,624
Total	62	14,151	5,552	245	524	6,592	2,206	5,837	39,001	116	74,286

6 In this section, unit type "Unknown" is referred to for units that the RTEP has not yet identified.
7 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 3-31 Existing PJM capacity: At June 30, 2010[8] (By zone and unit type (MW)) (See 2009 SOM, Table 3-43)

	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
AECO	0	0	608	23	0	0	1,281	0	8	1,919
AEP	0	4,355	3,629	57	1,005	2,106	21,256	0	901	33,308
AP	0	1,129	1,178	36	108	0	7,963	0	431	10,845
BGE	0	0	849	7	0	1,705	3,026	0	0	5,587
ComEd	0	1,814	7,110	111	0	10,376	7,090	0	1,765	28,265
DAY	0	0	1,358	52	0	0	3,572	3	0	4,985
DLCO	0	101	188	0	6	1,777	1,239	0	0	3,311
Dominion	0	3,173	3,853	160	3,558	3,494	8,617	0	0	22,855
DPL	0	376	2,496	96	0	0	2,007	0	0	4,975
External	0	974	1,890	0	0	439	10,064	0	185	13,552
JCPL	0	1,192	1,423	25	400	615	318	0	0	3,972
Met-Ed	0	2,000	406	23	20	805	890	0	0	4,143
PECO	1	2,552	836	7	1,642	4,509	2,129	3	0	11,679
PENELEC	0	0	287	45	505	0	6,834	0	447	8,117
Pepco	0	0	1,555	12	0	0	4,706	0	0	6,273
PPL	0	956	1,362	63	571	2,375	5,532	0	217	11,075
PSEG	0	2,921	2,856	0	5	3,553	2,535	10	0	11,880
Total	1	21,542	31,883	717	7,820	31,753	89,057	16	3,953	186,741

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

Table 3-32 PJM capacity age: At June 30, 2010 (MW) (See 2009 SOM, Table 3-44)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,307	18,886	380	10	0	2,089	16	3,953	42,641
10 to 20	0	3,976	4,740	129	49	0	6,148	0	0	15,042
20 to 30	0	158	480	38	3,438	16,186	9,997	0	0	30,296
30 to 40	0	101	5,276	39	435	14,953	31,345	0	0	52,149
40 to 50	0	0	2,501	128	2,480	615	24,363	0	0	30,086
50 to 60	0	0	0	4	348	0	13,611	0	0	13,963
60 to 70	0	0	0	0	32	0	1,356	0	0	1,388
70 to 80	0	0	0	0	314	0	149	0	0	463
80 to 90	0	0	0	0	486	0	0	0	0	486
90 to 100	0	0	0	0	200	0	0	0	0	200
100 and over	0	0	0	0	27	0	0	0	0	27
Total	1	21,542	31,883	717	7,820	31,753	89,057	16	3,953	186,741

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[9] (See 2009 SOM, Table 3-45)

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	Battery	0	0.0%	1	0.0%	0	1	0.0%
	Combined Cycle	0	0.0%	7,041	20.5%	4,293	11,334	29.1%
	Combustion Turbine	955	12.1%	8,220	23.9%	1,576	8,840	22.7%
	Diesel	49	0.6%	150	0.4%	51	152	0.4%
	Hydroelectric	2,042	25.8%	2,047	5.9%	0	2,047	5.3%
	Nuclear	615	7.8%	8,676	25.2%	510	8,572	22.0%
	Solar	0	0.0%	13	0.0%	1,533	1,546	4.0%
	Steam	4,240	53.7%	8,269	24.0%	771	4,800	12.3%
	Wind	0	0.0%	8	0.0%	1,516	1,524	3.9%
	Unknown	0	0.0%	0	0.0%	67	67	3.2%
	EMAAC Total	7,901	100.0%	34,425	100.0%	10,316	38,882	100.0%

Table continued next page

9 Percents shown in Table 3-33 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018 (See 2009 SOM, Table 3-45) (continued)

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
SWMAAC	Combined Cycle	0	0.0%	0	0.0%	2,025	2,025	16.7%
	Combustion Turbine	540	14.2%	2,404	20.3%	230	2,093	17.3%
	Diesel	0	0.0%	19	0.2%	6	25	0.2%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	27.6%
	Steam	3,267	85.8%	7,732	65.2%	132	4,597	38.0%
	Unknown	0	0.0%	0	0.0%	25	25	0.2%
	SWMAAC Total	3,807	100.0%	11,859	100.0%	4,058	12,110	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	40	40	0.2%
	Combined Cycle	0	0.0%	2,956	12.7%	650	3,606	17.0%
	Combustion Turbine	296	4.3%	2,054	8.8%	201	1,958	9.2%
	Diesel	35	0.5%	131	0.6%	53	148	0.7%
	Hydroelectric	444	6.5%	1,096	4.7%	175	1,270	6.0%
	Nuclear	0	0.0%	3,180	13.6%	1,624	4,804	22.6%
	Solar	0	0.0%	0	0.0%	120	120	0.6%
	Steam	6,042	88.6%	13,256	56.8%	133	7,346	34.6%
	Wind	0	0.0%	663	2.8%	1,279	1,942	9.2%
	Unknown	0	0.0%	0	0.0%	16	16	0.1%
	WMAAC Total	6,817	100.0%	23,335	100.0%	4,289	21,211	100.0%
RTO	Battery	0	0.0%	0	0.0%	22	22	0.0%
	Combined Cycle	0	0.0%	11,545	9.9%	7,184	18,729	12.9%
	Combustion Turbine	709	2.5%	19,206	16.4%	3,546	22,043	15.2%
	Diesel	48	0.2%	417	0.4%	135	504	0.3%
	Hydroelectric	1,401	5.0%	4,677	4.0%	350	3,626	2.5%
	Nuclear	0	0.0%	18,192	15.5%	2,818	21,010	14.5%
	Solar	0	0.0%	3	0.0%	553	555	0.4%
	Steam	25,931	92.3%	59,800	51.1%	4,802	38,671	26.7%
	Wind	0	0.0%	3,282	2.8%	36,206	39,488	27.3%
	Unknown	0	0.0%	0	0.0%	8	8	0.0%
	RTO Total	28,089	100.0%	117,121	100.0%	55,624	144,656	100.0%
All Areas	Total	46,614		186,741		74,286	216,859	

Characteristics of Wind Units

Table 3-34 Capacity factor of wind units in PJM, January through June 2010[10] (See 2009 SOM, Table 3-46)

Type of Resource	Capacity Factor	Total Hours	Installed Capacity (MW)
Energy-Only Resource	23.2%	60,730	1,412
Capacity Resource	32.3%	123,154	2,540
All Units	30.1%	183,884	3,953

Table 3-35 Wind resources in real time offering at a negative price in PJM, January through June 2010 (See 2009 SOM, Table 3-47)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	510.6	815	1.56%
All Wind	1,415.2	1,142	2.19%

Figure 3-4 Average hourly real-time generation of wind units in PJM, January through June 2010 (See 2009 SOM, Figure 3-11)

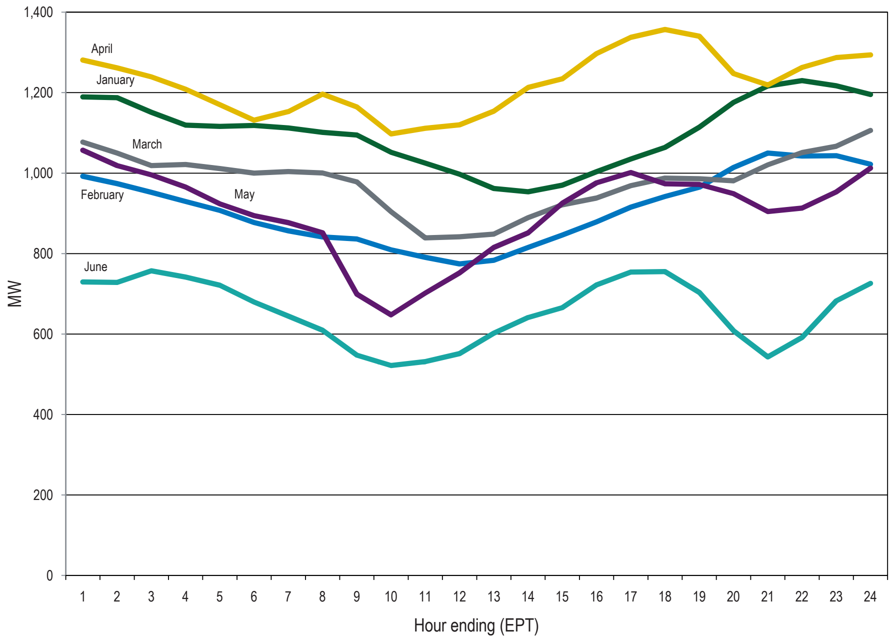


Table 3-36 Capacity factor of wind units in PJM by month, January through June 2010[11] (See 2009 SOM, Table 3-48)

Month	Generation (MWh)	Capacity Factor
January	818,423.9	38.2%
February	612,044.4	29.8%
March	727,819.1	30.7%
April	881,317.4	36.9%
May	670,571.5	27.2%
June	472,775.6	19.3%
July		
August		
September		
October		
November		
December		
Annual	4,182,951.9	30.1%

Table 3-37 Peak and off-peak seasonal capacity factor, average wind generation, and PJM load, January through June 2010 (See 2009 SOM, Table 3-49)

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	31.5%	35.8%	22.5%		29.1%
	Average Wind Generation	960.6	1,188.6	755.3		932.2
	Average Load	86,485.1	73,871.4	89,018.4		85,137.8
Off-Peak	Capacity Factor	34.1%	37.9%	23.9%		31.0%
	Average Wind Generation	1,033.9	1,257.9	802.8		990.4
	Average Load	75,824.0	59,326.6	70,803.5		71,476.4

10 The corresponding table in the *2009 Quarterly State of the Market Report for PJM: January through June*, reversed the labels for energy only resources and capacity resources data.

11 Capacity factor shown in Table 3-36 is based on all hours in January through June, 2010.

Figure 3-5 Average hourly day-ahead generation of wind units in PJM, January through June 2010 (See 2009 SOM, Figure 3-12)

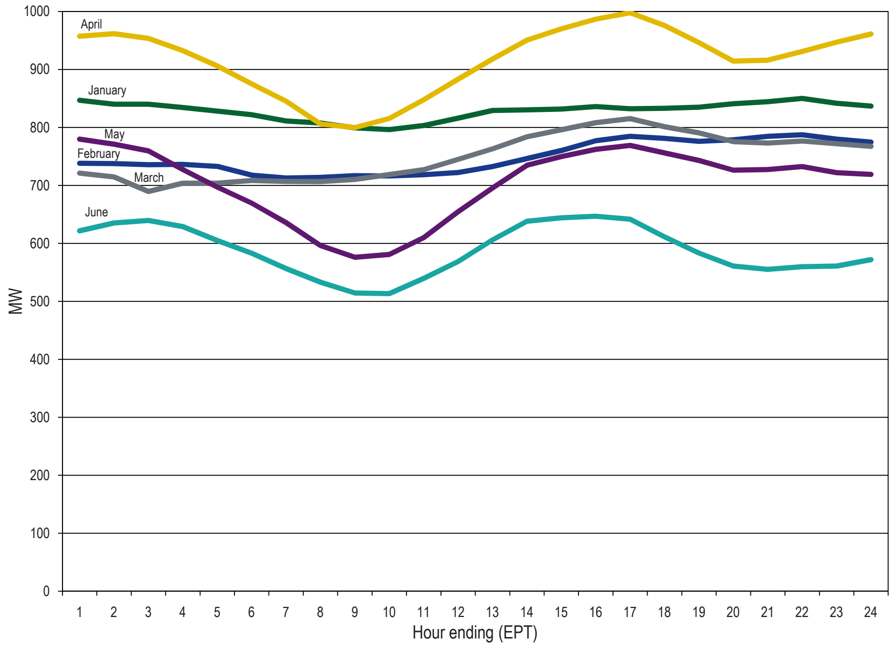
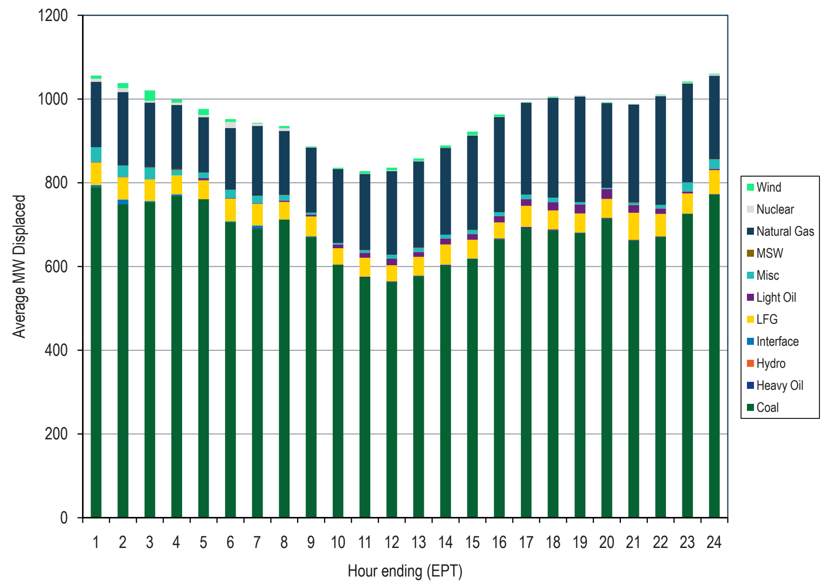


Figure 3-6 Marginal fuel at time of wind generation in PJM, January through June 2010 (See 2009 SOM, Figure 3-13)



Operating Reserve

Credit and Charge Categories

Table 3-38 Operating reserve credits and charges (See 2009 SOM, Table 3-50)

For Credits Received		By Charges Paid
Day ahead:		Day-ahead demand
Day-Ahead Energy Market	→	Decrement bids
Day-ahead import transactions		Day-ahead export transactions
Synchronous condensing	→	Real-time load
		Real-time export transactions
Balancing:		
Balancing energy market		Real-time deviations
Lost opportunity cost	→	from day-ahead schedules
Real-time import transactions		
Balancing Energy Market Credits Received		**By Balancing Energy Market Charges Paid**
By (RTO, Eastern Region, Western Region)		Real-time load
Reliability Credits	→	Real-time export transactions
Deviation Credits	→	Real-time deviations
		from day-ahead schedules

Table 3-39 Operating reserve deviations (See 2009 SOM, Table 3-51)

	Deviations	
Day ahead		Real time
Day-ahead decrement bids	Demand (Withdrawal)	Real-time load
Day-ahead load	(RTO, East, West)	Real-time sales
Day-ahead sales		Real-time export transactions
Day-ahead export transactions		
Day-ahead increment offers	Supply (Injection)	Real-time purchases
Day-ahead purchases	(RTO, East, West)	Real-time import transactions
Day-ahead import transactions		
Day-ahead scheduled generation	Generator (Unit)	Real-time generation

Balancing Credits and Charges

Table 3-40 Balancing operating reserve allocation process (See 2009 SOM, Table 3-52)

	Reliability Credits	Deviation Credits
RTO	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV
East	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Credit and Charge Results

Overall Results

Table 3-41 Monthly operating reserve charges: Calendar year 2009 and January through June 2010 (See 2009 SOM, Table 3-54)[12]

	2009 Charges				2010 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$9,260,150	$1,328,814	$30,116,725	$40,705,689	$10,281,351	$50,022	$40,461,023	$50,792,396
Feb	$7,434,068	$839,679	$16,548,988	$24,822,735	$11,425,494	$14,715	$22,344,500	$33,784,709
Mar	$9,549,963	$108,664	$26,025,562	$35,684,189	$8,836,886	$122,817	$16,823,227	$25,782,929
Apr	$6,998,364	$19,929	$13,251,273	$20,269,566	$7,633,141	$93,253	$22,674,231	$30,400,625
May	$6,024,108	$5,543	$15,490,257	$21,519,908	$5,127,307	$131,600	$38,584,716	$43,843,623
Jun	$6,722,329	$0	$19,339,846	$26,062,175	$3,511,264	$33,923	$56,519,115	$60,064,302
Jul	$8,210,636	$38,643	$17,728,976	$25,978,255				
Aug	$7,697,174	$1	$21,164,586	$28,861,761				
Sep	$6,057,598	$13,611	$13,471,368	$19,542,577				
Oct	$7,046,301	$0	$17,026,425	$24,072,727				
Nov	$8,617,280	$22,639	$12,888,600	$21,528,519				
Dec	$11,323,263	$117,573	$25,353,409	$36,794,245				
Total	$94,941,235	$2,495,097	$228,406,015	$325,842,346	$46,815,443	$446,330	$197,406,812	$244,668,585
Share of Annual Charges	29.1%	0.8%	70.1%	100.0%	19.1%	0.2%	80.7%	100.0%

12 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The figures reported in this section reflect the figures at the time this report was created.

Table 3-42 Regional balancing charges allocation: January through June 2010[13] (See 2009 SOM, Table 3-55)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$15,917,613 11.3%	$619,122 0.4%	$16,536,736 11.7%	$40,184,542 28.5%	$22,663,866 16.1%	$11,833,894 8.4%	$74,682,303 53.0%	$91,219,038 64.7%
East	$27,351,105 19.4%	$1,100,323 0.8%	$28,451,428 20.2%	$4,599,507 3.3%	$2,650,810 1.9%	$1,054,579 0.7%	$8,304,896 5.9%	$36,756,324 26.1%
West	$8,784,110 6.2%	$285,356 0.2%	$9,069,466 6.4%	$2,130,462 1.5%	$961,154 0.7%	$797,715 0.6%	$3,889,331 2.8%	$12,958,797 9.2%
Total	$52,052,828 36.9%	$2,004,802 1.4%	$54,057,630 38.4%	$46,914,512 33.3%	$26,275,830 18.6%	$13,686,188 9.7%	$86,876,529 61.6%	$140,934,159 100%

Deviations

Allocation

Table 3-43 Monthly balancing operating reserve deviations (MWh): Calendar year 2009 and January through June 2010 (See 2009 SOM, Table 3-56)

	2009 Deviations				2010 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,128,112	5,575,170	2,630,917	17,334,199	9,439,465	5,707,965	2,709,298	17,856,728
Feb	7,044,702	4,153,575	2,107,229	13,305,505	7,675,656	5,332,236	2,462,260	15,470,152
Mar	7,214,090	4,352,550	2,409,507	13,976,146	8,101,950	5,138,264	2,266,934	15,507,148
Apr	6,873,427	3,836,896	2,275,153	12,985,477	7,006,983	4,668,407	2,152,689	13,828,078
May	6,958,699	5,184,983	2,382,351	14,526,033	9,004,034	4,228,004	2,430,731	15,662,769
Jun	8,569,879	4,603,052	2,635,991	15,808,922	10,937,311	3,964,478	3,217,112	18,118,902
Jul	9,233,511	5,129,409	2,243,337	16,606,257				
Aug	9,961,944	5,425,344	2,427,539	17,814,827				
Sep	7,972,378	4,171,876	2,109,506	14,253,759				
Oct	7,028,775	4,543,635	2,203,723	13,776,133				
Nov	6,742,675	4,248,221	2,193,013	13,183,910				
Dec	8,301,680	4,682,157	3,113,047	16,096,884				
Total	95,029,874	55,906,867	28,731,313	179,668,054	52,165,400	29,039,354	15,239,023	96,443,777
Share of Annual Deviations	52.9%	31.1%	16.0%	100.0%	54.1%	30.1%	15.8%	100.0%

13 The total charges shown in Table 3-42 do not equal the total balancing charges shown in Table 3-41 because the totals in Table 3-41 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-42 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 3-44 Regional charges determinants (MWh): January through June 2010 (See 2009 SOM, Table 3-57)

	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	339,214,651	13,026,941	352,241,592	52,165,400	29,039,354	15,239,023	96,443,777	448,685,369
East	185,390,813	7,537,156	192,927,969	33,818,304	20,029,790	7,984,909	61,833,003	254,760,972
West	153,823,838	5,489,785	159,313,623	18,202,862	8,959,850	7,254,114	34,416,826	193,730,449

Balancing Operating Reserve Charge Rate

Figure 3-7 Daily RTO reliability and deviation rates ($/MWh): January through June 2010 (See 2009 SOM, Figure 3-14)

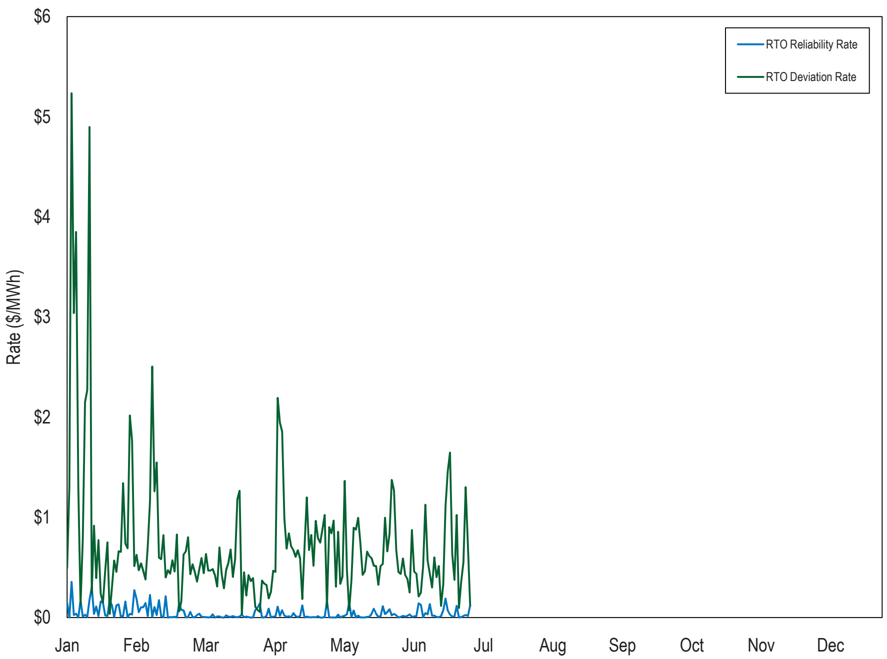


Figure 3-8 Daily regional reliability and deviation rates ($/MWh): January through June 2010 (See 2009 SOM, Figure 3-15)

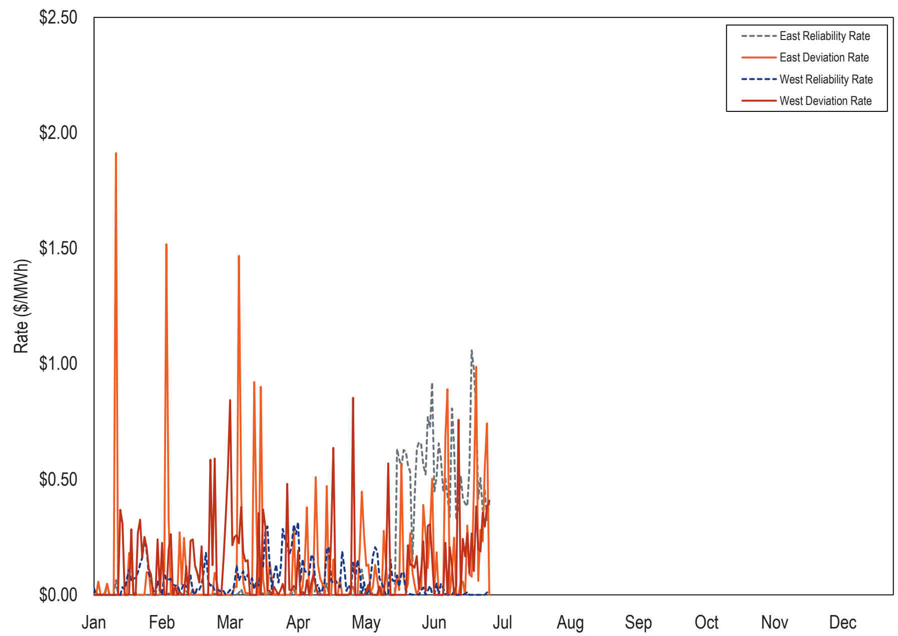


Table 3-45 Regional balancing operating reserve rates ($/MWh): January through June 2010 (See 2009 SOM, Table 3-58)

	Reliability	Deviations
RTO	0.044	0.736
East	0.862	0.133
West	0.058	0.117

Operating Reserve Credits by Category

Figure 3-9 Operating reserve credits: January through June 2010 (See 2009 SOM, Figure 3-16)

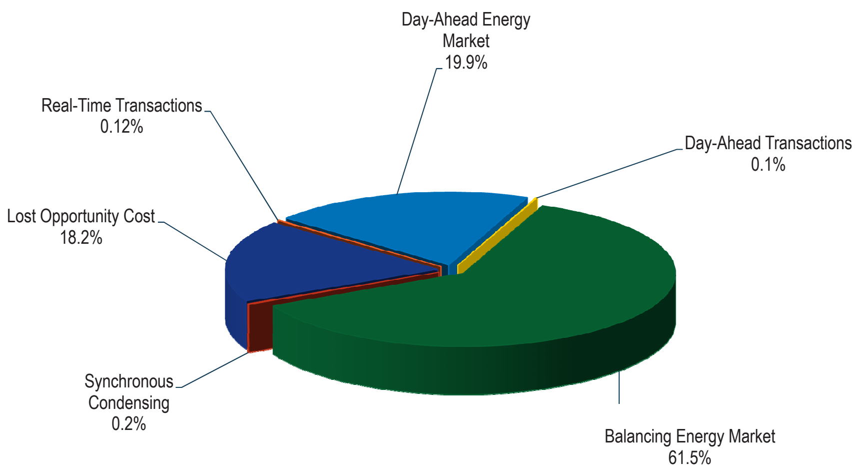


Table 3-46 Credits by month (By operating reserve market): January through June 2010 (See 2009 SOM, Table 3-59)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$10,199,534	$81,816	$50,022	$34,146,809	$0	$3,322,385	$47,800,567
Feb	$11,382,585	$42,910	$14,715	$17,778,182	$77,139	$1,710,205	$31,005,735
Mar	$8,831,771	$5,115	$122,817	$13,931,246	$15,603	$1,971,841	$24,878,393
Apr	$7,633,141	$0	$93,253	$16,911,974	$0	$4,512,804	$29,151,173
May	$5,117,845	$9,462	$131,600	$23,011,853	$1,236	$15,434,268	$43,706,265
Jun	$3,469,143	$42,121	$33,923	$38,429,261	$196,537	$15,598,399	$57,769,384
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	$46,634,019	$181,424	$446,330	$144,209,326	$290,515	$42,549,903	$234,311,518
Share of Credits	19.9%	0.1%	0.2%	61.5%	0.1%	18.2%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-47 Credits by unit types (By operating reserve market): January through June 2010 (See 2009 SOM, Table 3-60)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	36.6%	0.0%	58.5%	4.9%	$72,453,861
Combustion Turbine	0.7%	0.7%	58.4%	40.1%	$61,763,265
Diesel	0.7%	0.0%	89.4%	9.9%	$220,336
Hydro	0.0%	0.0%	100.0%	0.0%	$30,592
Landfill	0.0%	0.0%	0.0%	100.0%	$9,140,793
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	21.9%	0.0%	72.5%	5.6%	$89,992,739
Wind Farm	0.0%	0.0%	100.0%	0.0%	$154,268

Table 3-48 Credits by operating reserve market (By unit type): January through June 2010 (See 2009 SOM, Table 3-61)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	56.8%	0.0%	29.4%	8.4%
Combustion Turbine	0.9%	100.0%	25.0%	58.3%
Diesel	0.0%	0.0%	0.1%	0.1%
Hydro	0.0%	0.0%	0.0%	0.0%
Landfill	0.0%	0.0%	0.0%	21.5%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	42.2%	0.0%	45.3%	11.8%
Wind Farm	0.0%	0.0%	0.1%	0.0%
Total	$46,634,019	$446,330	$144,125,601	$42,549,903

Geography of Balancing Credits and Charges

Table 3-49 Monthly balancing operating reserve charges and credits to generators (By location): January through June 2010 (See 2009 SOM, Table 3-65)

	Eastern Region						Western Region							
	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Total Unit Deviation Charges Percent of Total Operating Reserve Charges	Total Unit Credits Percent of Total Operating Reserve Credits
Jan	$1,913,490	$248,583	$2,162,073	$29,069,084	$2,719,515	$31,788,599	$1,971,007	$262,958	$2,233,964	$5,077,725	$602,870	$5,680,596	8.6%	78.4%
Feb	$1,069,496	$138,135	$1,207,631	$14,194,451	$1,373,952	$15,568,403	$998,751	$132,513	$1,131,264	$3,583,730	$336,253	$3,919,983	6.9%	62.9%
Mar	$591,603	$125,603	$717,206	$8,223,758	$1,399,277	$9,623,035	$754,381	$166,300	$920,681	$5,707,488	$572,564	$6,280,053	6.3%	63.9%
Apr	$899,527	$342,395	$1,241,923	$12,315,307	$3,367,832	$15,683,139	$1,096,031	$391,699	$1,487,730	$4,596,667	$1,144,973	$5,741,640	9.0%	73.5%
May	$912,304	$1,201,575	$2,113,879	$17,594,661	$13,639,265	$31,233,926	$923,809	$1,180,445	$2,104,254	$5,417,192	$1,795,003	$7,212,196	9.6%	88.0%
Jun	$1,333,270	$1,469,883	$2,803,154	$33,433,440	$14,468,721	$47,902,161	$1,222,519	$1,360,982	$2,583,502	$4,995,821	$1,129,678	$6,125,499	8.9%	93.5%
Jul														
Aug														
Sep														
Oct														
Nov														
Dec														
Average	49.1%	50.2%	49.5%	79.6%	86.9%	81.3%	50.9%	49.8%	50.5%	20.4%	13.1%	18.7%	8.2%	76.7%

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-50 Regional balancing operating reserve credits: January through June 2010 (See 2009 SOM, Table 3-66)[14]

	Reliability Credits	Deviation Credits	Total Credits
RTO	$16,536,736	$74,682,303	$91,219,038
East	$28,451,428	$8,304,896	$36,756,324
West	$9,069,466	$3,889,331	$12,958,797
Total	$54,057,630	$86,876,529	$140,934,159

Table 3-51 Total deviations: January through June 2010 (See 2009 SOM, Table 3-67)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	52,165,400	29,039,354	15,239,023	96,443,777

Table 3-52 Charge allocation under old operating reserve construct: January through June 2010 (See 2009 SOM, Table 3-68)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	52,165,400	29,039,354	15,239,023	96,443,777
Balancing Rate ($/MWh)	1.461	1.461	1.461	1.461
Charges ($)	$76,229,768	$42,435,470	$22,268,922	$140,934,159

Table 3-53 Actual regional credits, charges, rates and charge allocation (MWh): January through June 2010 (See 2009 SOM, Table 3-69)

	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	$16,536,736	352,241,592	0.047	$16,536,736	$74,682,303	96,443,777	0.774	$74,682,303	$91,219,038
East	$28,451,428	192,927,969	0.147	$28,451,428	$8,304,896	61,833,003	0.134	$8,304,896	$36,756,324
West	$9,069,466	159,313,623	0.057	$9,069,466	$3,889,331	34,416,826	0.113	$3,889,331	$12,958,797
Total	$54,057,630	352,241,592	NA	$54,057,630	$86,876,529	96,443,777	NA	$86,876,529	$140,934,159

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

Table 3-54 Difference in total charges between old rules and new rules: January through June 2010 (See 2009 SOM, Table 3-70)

	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	$76,229,768	$42,435,470	$22,268,922	$140,934,159
Charges (Current)	$52,052,828	$2,004,802	$54,057,630	$46,914,512	$26,275,830	$13,686,188	$86,876,529
Difference	$52,052,828	$2,004,802	$54,057,630	($29,315,256)	($16,159,640)	($8,582,734)	($54,057,630)

Impact on decrement bids and incremental offers

Table 3-55 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): January through June 2010 (see 2009 SOM, Table 3-71)

Month	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
Feb	8,323,844	11,828,780	2,004,162	2,234,045
Mar	8,032,429	11,159,303	2,150,898	2,594,826
Apr	7,568,471	9,989,951	2,214,314	2,066,270
May	8,306,597	11,573,314	2,250,271	3,437,786
Jun	8,304,139	12,735,819	2,223,204	4,058,044
Total	48,826,912	70,316,684	13,306,701	17,843,017

Table 3-56 Comparison of balancing operating reserve charges to virtual bids: January through June 2010 (See 2009 SOM, Table 3-72)

Month	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,703,717	$10,186,571	($2,517,146)
Feb	$5,381,782	$3,935,858	($1,445,924)
Mar	$4,614,252	$3,470,186	($1,144,066)
Apr	$6,472,900	$5,265,681	($1,207,219)
May	$13,650,729	$9,963,541	($3,687,188)
Jun	$18,578,834	$10,473,714	($8,105,120)
Total	$61,402,214	$43,295,552	($18,106,662)

Table 3-57 Summary of impact on virtual bids under balancing operating reserve allocation: January through June 2010 (See 2009 SOM, Table 3-73)

Region	Adjusted Increment Offer Deviations	Adjusted Decrement Bid Deviations	Total Adjusted Virtual Deviations	Balancing Rate Under Old Rules	Balancing Rate Under Current Rules	Charges Under Old Rules	Charges Under Current Rules	Differerence
RTO	13,306,701	17,843,017	31,149,718	1.87	1.19	$61,402,213	$39,270,576	($22,131,638)
East	8,947,802	11,120,832	20,068,635	0.00	0.11	$0	$2,843,731	$2,843,731
West	4,309,184	6,577,952	10,887,136	0.00	0.00	$0	$1,181,245	$1,181,245

Segmented Make Whole Payments

Table 3-58 Impact of segmented make whole payments: December 2008 through June 2010 (See 2009 SOM, Table 3-74)

Year	Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
2008	Dec	$17,879,706	$18,564,627	$684,920
2009	Jan	$24,958,891	$26,413,119	$1,454,228
2009	Feb	$13,834,755	$14,391,550	$556,795
2009	Mar	$21,434,893	$22,200,141	$765,248
2009	Apr	$10,532,594	$10,741,260	$208,666
2009	May	$13,499,668	$13,813,209	$313,541
2009	Jun	$15,111,383	$16,058,545	$947,162
2009	Jul	$14,657,498	$15,414,023	$756,525
2009	Aug	$14,467,711	$15,602,754	$1,135,043
2009	Sep	$10,293,949	$10,576,618	$282,669
2009	Oct	$14,337,978	$14,605,878	$267,900
2009	Nov	$8,889,163	$9,091,845	$202,682
2009	Dec	$19,403,859	$20,002,885	$599,026
2010	Jan	$32,982,105	$33,924,489	$942,385
2010	Feb	$17,321,317	$17,609,133	$287,815
2010	Mar	$13,458,059	$13,672,111	$214,052
2010	Apr	$16,283,918	$16,880,164	$596,246
2010	May	$21,738,521	$23,352,543	$1,614,023
2010	Jun	$36,113,341	$38,716,050	$2,602,710
Total		$337,199,307	$351,630,944	$14,431,637

Table 3-59 Impact of segmented make whole payments (By unit type): January through June 2010 (See 2009 SOM, Table 3-75)[15]

Unit Type	Number of Unit-Days	Average Daily Balancing Credits (Old Rules)	Average Daily Balancing Credits (New Rules)	Average Daily Difference	Total Balancing Credits (Old Rules)	Total Balancing Credits (New Rules)	Total Difference
Combined-Cycle	3926	$10,065	$10,800	$735	$39,514,755	$42,399,714	$2,884,959
Large Frame Combustion Turbine (135 - 180 MW)	1181	$11,330	$12,414	$1,085	$13,380,221	$14,661,191	$1,280,970
Medium Frame Combustion Turbine (30 - 65 MW)	3781	$3,204	$3,446	$241	$12,115,045	$13,027,503	$912,457
Medium-Large Frame Combustion Turbine (65 - 125 MW)	944	$6,791	$7,129	$338	$6,410,706	$6,730,045	$319,339
Petroleum/Gas Steam (Post-1985)	958	$2,597	$2,902	$306	$2,487,584	$2,780,314	$292,729
Sub-Critical Coal	15002	$1,385	$1,403	$18	$20,783,500	$21,053,521	$270,021
Petroleum/Gas Steam (Pre-1985)	365	$94,958	$95,601	$644	$34,659,502	$34,894,504	$235,002
Small Frame Combustion Turbine (0 - 29 MW)	1734	$1,050	$1,082	$32	$1,820,508	$1,876,677	$56,169
Diesel	2204	$87	$89	$3	$191,491	$197,075	$5,584
Super-Critical Coal	4736	$1,380	$1,380	$0	$6,533,948	$6,533,948	$0
Hydro	379	$0	$0	$0	$0	$0	$0
Nuclear	638	$0	$0	$0	$0	$0	$0

Table 3-60 Share of balancing operating reserve increases for segmented make whole payments (By unit type): January through June 2010 (See 2009 SOM, Table 3-76)

Unit Type	Share of Increase
Combined-Cycle	46.1%
Steam	9.8%
Combustion Turbines	35.1%
Diesel	0.1%

15 In previous State of the Market reports, the columns Average Daily Balancing Credits (Old and New rules), and Total Balancing Credits (Old and Current rules), were the average and sums of only the observations in which there was a difference for a unit's balancing credits for the day under each method of calculation. The table now reflects the average and total credits for all observations in the time period, regardless of whether there was a difference for that day when calculating credits under each rule. While the differences between the new and old rules remain the same, the Total Balancing Credits columns now reflect the total sum of the time period's balancing operating reserves credits, as shown in Table 3-46.

Unit Operating Parameters

Table 3-61 Unit Parameter Limited Schedule Matrix (See 2009 SOM, Table 3-77)

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

Table 3-62 Units receiving credits from a parameter limited schedule: January through June 2010 (See 2009 SOM, Table 3-78)

Unit Type	Number of Units	Observations
Combined-Cycle	2	7
Large Frame Combustion Turbine (135 - 180 MW)	5	38
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	74
Petroleum/Gas Steam (Pre-1985)	2	5
Sub-Critical Coal	17	151
Super-Critical Coal	1	1

Concentration of Unit Ownership for Operating Reserve Credits

Concentration of Operating Reserve Credits

Table 3-63 Unit operating reserve credits for units (By zone): January through June 2010 (See 2009 SOM, Table 3-80)

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	$261,191	$3,971	$859,214	$496,445	$1,620,822	0.7%
AEP	$1,559,386	$9,688	$17,218,803	$447,100	$19,234,977	8.2%
AP	$979,263	$0	$2,404,974	$3,920,835	$7,305,072	3.1%
BGE	$2,770,122	$0	$3,591,870	$28,866	$6,390,858	2.7%
ComEd	$604,478	$4,080	$3,694,172	$1,172,345	$5,475,075	2.3%
DAY	$134,187	$0	$834,618	$25,350	$994,155	0.4%
Dominion	$809,590	$0	$12,110,290	$25,837,179	$38,757,058	16.6%
DPL	$1,719,157	$7,490	$4,128,086	$564,229	$6,418,962	2.7%
DLCO	$1,941,979	$0	$5,226,057	$15,712	$7,183,748	3.1%
JCPL	$2,230,184	$0	$3,285,093	$317,970	$5,833,248	2.5%
Met-Ed	$217,258	$0	$1,002,053	$73,804	$1,293,116	0.6%
PECO	$1,550,729	$2,095	$2,476,531	$758,569	$4,787,925	2.0%
PENELEC	$54,374	$23,603	$482,424	$386,671	$947,072	0.4%
Pepco	$2,173,991	$0	$37,917,784	$7,549,667	$47,641,442	20.4%
PPL	$105,981	$0	$4,140,949	$546,149	$4,793,079	2.0%
PSEG	$29,522,149	$395,402	$44,836,406	$409,013	$75,162,970	32.1%
External	$0	$0	$0	$0	$0	0.0%
Total	$46,634,019	$446,330	$144,209,326	$42,549,903	$233,839,578	100.0%

Table 3-64 Top 10 units and organizations receiving total operating reserve credits: January through June 2010 (See 2009 SOM, Table 3-81)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$26,565,270	11.4%	11.4%	$74,478,710	31.9%	31.9%
2	$19,227,389	8.2%	19.6%	$33,759,344	14.4%	46.3%
3	$14,170,856	6.1%	25.6%	$33,170,782	14.2%	60.5%
4	$13,069,594	5.6%	31.2%	$15,360,288	6.6%	67.0%
5	$10,953,365	4.7%	35.9%	$9,600,111	4.1%	71.1%
6	$3,475,866	1.5%	37.4%	$8,824,067	3.8%	74.9%
7	$3,164,328	1.4%	38.8%	$8,477,542	3.6%	78.5%
8	$3,084,478	1.3%	40.1%	$7,873,726	3.4%	81.9%
9	$2,740,601	1.2%	41.2%	$5,108,985	2.2%	84.1%
10	$2,523,122	1.1%	42.3%	$3,830,642	1.6%	85.7%

Table 3-65 Top 10 units and organizations receiving day-ahead generator credits: January through June 2010 (See 2009 SOM, Table 3-82)

	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	$11,916,077	25.6%	25.6%	$29,477,589	63.2%	63.2%
2	$7,522,447	16.1%	41.7%	$2,834,009	6.1%	69.3%
3	$6,408,267	13.7%	55.4%	$2,076,778	4.5%	73.7%
4	$1,875,580	4.0%	59.4%	$1,875,580	4.0%	77.8%
5	$1,770,278	3.8%	63.2%	$1,303,964	2.8%	80.6%
6	$1,242,597	2.7%	65.9%	$1,295,994	2.8%	83.3%
7	$1,225,594	2.6%	68.5%	$1,001,121	2.1%	85.5%
8	$1,001,121	2.1%	70.7%	$850,710	1.8%	87.3%
9	$784,389	1.7%	72.4%	$839,016	1.8%	89.1%
10	$715,837	1.5%	73.9%	$832,632	1.8%	90.9%

Table 3-66 Top 10 units and organizations receiving synchronous condensing credits: January through June 2010 (See 2009 SOM, Table 3-83)

	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	$36,267	8.1%	8.1%	$395,402	88.6%	88.6%
2	$30,100	6.7%	14.9%	$23,603	5.3%	93.9%
3	$29,935	6.7%	21.6%	$11,462	2.6%	96.4%
4	$27,984	6.3%	27.8%	$9,688	2.2%	98.6%
5	$27,723	6.2%	34.1%	$4,080	0.9%	99.5%
6	$25,458	5.7%	39.8%	$2,095	0.47%	100.0%
7	$23,378	5.2%	45.0%			
8	$19,037	4.3%	49.3%			
9	$18,865	4.2%	53.5%			
10	$18,401	4.1%	57.6%			

Table 3-67 Top 10 units and organizations receiving balancing generator credits: January through June 2010 (See 2009 SOM, Table 3-84)

	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	$20,157,003	14.0%	14.0%	$44,196,706	30.6%	30.6%
2	$13,832,542	9.6%	23.6%	$32,397,635	22.5%	53.1%
3	$10,952,636	7.6%	31.2%	$13,774,804	9.6%	62.7%
4	$7,309,374	5.1%	36.2%	$13,395,009	9.3%	72.0%
5	$5,546,947	3.8%	40.1%	$7,312,384	5.1%	77.0%
6	$3,084,478	2.1%	42.2%	$6,593,455	4.6%	81.6%
7	$2,523,122	1.7%	44.0%	$4,918,949	3.4%	85.0%
8	$2,103,750	1.5%	45.4%	$2,090,078	1.4%	86.5%
9	$1,977,893	1.4%	46.8%	$1,790,532	1.2%	87.7%
10	$1,856,180	1.3%	48.1%	$1,742,895	1.2%	88.9%

Table 3-68 Top 10 units and organizations receiving lost opportunity cost credits: January through June 2010 (See 2009 SOM, Table 3-85)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$2,859,534	6.7%	6.7%	$18,936,757	44.5%	44.5%
2	$1,867,852	4.4%	11.1%	$9,597,489	22.6%	67.1%
3	$1,666,721	3.9%	15.0%	$2,975,894	7.0%	74.1%
4	$1,664,106	3.9%	18.9%	$2,571,183	6.0%	80.1%
5	$1,349,602	3.2%	22.1%	$1,829,329	4.3%	84.4%
6	$1,343,538	3.2%	25.3%	$765,678	1.8%	86.2%
7	$1,319,649	3.1%	28.4%	$689,365	1.6%	87.8%
8	$1,293,233	3.0%	31.4%	$588,540	1.4%	89.2%
9	$1,292,035	3.0%	34.4%	$446,261	1.0%	90.2%
10	$1,281,785	3.0%	37.5%	$442,924	1.0%	91.3%

Eastern Reliability

A Change in Market Conditions

For the first six months of 2009, Eastern and Western regional charges were 25.9 percent of all balancing operating reserve charges. Eastern and Western regional reliability charges were 16.7 percent of all balancing operating reserve reliability charges ($15,478,488 of $92,960,347) and of that 16.7 percent, only 0.4 percent was in the East, or $336,190. (See Table 3-69.)

Table 3-69 Regional balancing charges allocation: January through June 2009 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$2,749,936 3.0%	$108,748 0.1%	$2,858,684 3.1%	$34,212,966 36.8%	$20,980,028 22.6%	$10,893,912 11.7%	$66,086,906 71.1%	$68,945,590 74.2%
East	$324,661 0.3%	$11,529 0.0%	$336,190 0.4%	$3,382,299 3.6%	$1,927,684 2.1%	$989,854 1.1%	$6,299,837 6.8%	$6,636,027 7.1%
West	$14,474,332 15.6%	$667,966 0.7%	$15,142,298 16.3%	$1,111,579 1.2%	$755,649 0.8%	$369,206 0.4%	$2,236,433 2.4%	$17,378,731 18.7%
Total	$17,548,928 18.9%	$788,243 0.8%	$18,337,172 19.7%	$38,706,844 41.6%	$23,663,360 25.5%	$12,252,972 13.2%	$74,623,176 80.3%	$92,960,347 100%

The results for the first six months of 2010 were significantly different than the results for the first six months of 2009. Overall balancing operating reserve charges increased, comprised of an increase in RTO charges, a significant increase in Eastern charges and a decrease in Western charges. In particular, Eastern regional reliability charges increased disproportionately between 2009 and 2010. Overall, the proportion of deviation charges decreased substantially and the proportion of reliability charges increased correspondingly. Table 3-70 shows the allocation of balancing charges for the first six months of 2010.

Table 3-70 Regional balancing charges allocation: January through June 2010 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$15,917,613 11.3%	$619,122 0.4%	$16,536,736 11.7%	$40,184,542 28.5%	$22,663,866 16.1%	$11,833,894 8.4%	$74,682,303 53.0%	$91,219,038 64.7%
East	$27,351,105 19.4%	$1,100,323 0.8%	$28,451,428 20.2%	$4,599,507 3.3%	$2,650,810 1.9%	$1,054,579 0.7%	$8,304,896 5.9%	$36,756,324 26.1%
West	$8,784,110 6.2%	$285,356 0.2%	$9,069,466 6.4%	$2,130,462 1.5%	$961,154 0.7%	$797,715 0.6%	$3,889,331 2.8%	$12,958,797 9.2%
Total	$52,052,828 36.9%	$2,004,802 1.4%	$54,057,630 38.4%	$46,914,512 33.3%	$26,275,830 18.6%	$13,686,188 9.7%	$86,876,529 61.6%	$140,934,159 100.0%

Table 3-71 shows the differences between the allocation of balancing operating reserve charges for the first six months of 2009 and the first six months of 2010. The percentages in the table are the differences in the share of total allocation between the two time periods. For example, RTO deviation charges represented 71.1 percent of all balancing operating reserve charges for the first half of 2009, and 53.0 percent of all balancing operating reserve charges for the first half of 2010, a decrease in share of 18.1 percentage points.

Table 3-71 Differences between regional balancing charges allocation: January through June 2009 and 2010 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$13,167,677 8.3%	$510,375 0.3%	$13,678,052 8.7%	$5,971,577 (8.3%)	$1,683,838 (6.5%)	$939,982 (3.3%)	$8,595,397 (18.1%)	$22,273,449 (9.4%)
East	$27,026,444 19.1%	$1,088,794 0.8%	$28,115,238 19.8%	$1,217,208 (0.4%)	$723,127 (0.2%)	$64,725 (0.3%)	$2,005,059 (0.9%)	$30,120,298 18.9%
West	($5,690,222) (9.3%)	($382,610) (0.5%)	($6,072,832) (9.9%)	$1,018,884 0.3%	$205,505 (0.1%)	$428,509 0.2%	$1,652,898 0.4%	($4,419,934) (9.5%)
Total	$34,503,900 18.1%	$1,216,559 0.6%	$35,720,458 18.6%	$8,207,668 (8.3%)	$2,612,470 (6.8%)	$1,433,216 (3.5%)	$12,253,354 (18.6%)	$47,973,812 0.0%

Table 3-72 shows the change in the total balancing operating reserve charges allocated to each category between the first six months of 2009 and the first six months of 2010. For example, the total balancing operating reserve charges allocated to RTO deviations increased 13.0 percent ($74,682,303 compared to $66,086,906).

Table 3-72 Table 35 Percent differences between regional balancing charges allocation: January through June 2009 and 2010 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	478.8%	469.3%	478.5%	17.5%	8.0%	8.6%	13.0%	32.3%
East	8324.5%	9443.6%	8362.9%	36.0%	37.5%	6.5%	31.8%	453.9%
West	(39.3%)	(57.3%)	(40.1%)	91.7%	27.2%	116.1%	73.9%	(25.4%)
Total	196.6%	154.3%	194.8%	21.2%	11.0%	11.7%	16.4%	51.6%

As shown in Table 3-71 and Table 3-72, the total balancing operating reserves charges allocated to Eastern reliability charges increased $28,115,238, from $336,190 in the first half of 2009, to $28,451,429 in the first half of 2010. Of this increase, 96.1 percent, or $27,026,444, was paid by real-time load, while the remainder, $1,088,794 was paid by real-time exports.

Figure 3-10 shows the regional reliability and deviation credits since the introduction of the modified Operating Reserve Business Rules on December 1, 2008. Under the old operating reserve construct, all balancing operating reserve credits were allocated to demand, supply, and generator deviations. Under the new rules, only credits that are assigned for deviation purposes (credits to units that are used in real-time to offset deviations from day-ahead unit commitments) are allocated to demand, supply, and generator deviations. Credits to units that are used for conservative operations to ensure the maintenance of system reliability are categorized as reliability credits and allocated to real-time load and exports. Reliability and deviation credits are further categorized as RTO, East, and West credits, depending on the voltage and location of the transmission constraint the unit is considered to be running for. Credits to units operating for transmission constraints at the 765kV and 500kV level are categorized as RTO credits, and for lower voltages are categorized as East or West credits, depending on location. Reliability credits to date were 19.7 percent of total balancing operating reserve credits in the first half of 2009 but increased to 38.4 percent in the first half of 2010. As shown in Figure 3-10, Eastern reliability credits increased from $290,150 for the first quarter of 2010, to $28,161,278 in the second quarter, with most of the increase occurring in June. Table 3-73 shows the actual credits for each month since December 2008.

Figure 3-10 Regional reliability and deviation balancing operating reserve credits: December 2008 through June 2010 (New Figure)

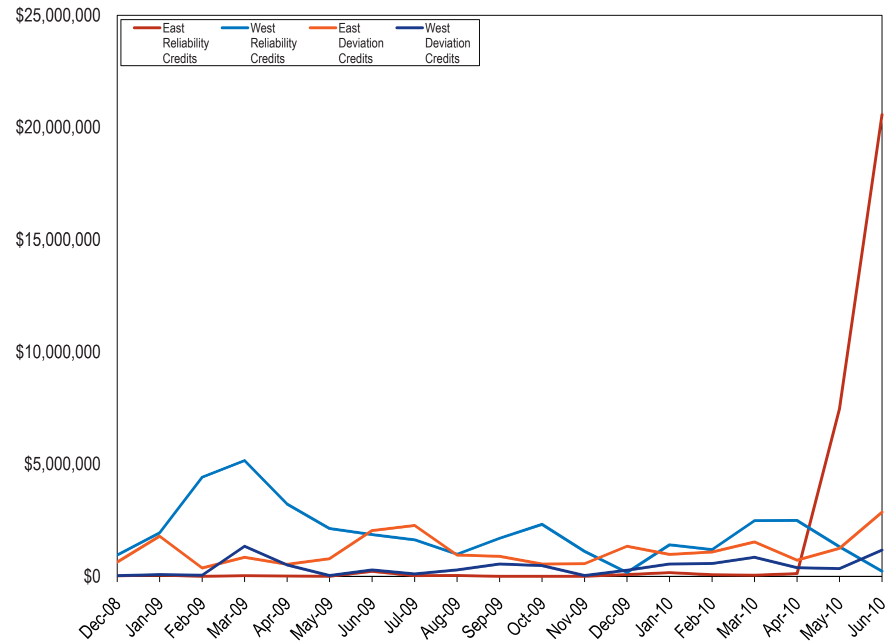


Table 3-73 Regional reliability and deviation balancing operating reserve credits: December 2008 through June 2010 (New Table)

Date	RTO Reliability Credits	East Reliability Credits	West Reliability Credits	RTO Deviation Credits	East Deviation Credits	West Deviation Credits
Dec-08	$1,122,812	$24,194	$953,097	$15,947,328	$638,315	$29,114
Jan-09	$1,206,262	$50,436	$1,942,604	$21,345,280	$1,789,530	$84,818
Feb-09	$437,339	$2,900	$4,422,782	$31,413,796	$371,385	$55,703
Mar-09	$625,452	$34,935	$5,162,875	$14,284,193	$851,527	$1,341,292
Apr-09	$474,138	$18,775	$3,225,567	$6,014,192	$537,604	$507,227
May-09	$220,958	$6,847	$2,132,991	$10,624,328	$789,721	$38,640
Jun-09	$199,855	$222,308	$1,863,966	$11,443,774	$2,041,684	$286,959
Jul-09	$205,809	$33,195	$1,625,620	$11,281,232	$2,269,772	$108,287
Aug-09	$241,597	$38,108	$989,805	$13,133,000	$954,148	$290,021
Sep-09	$438,538	$0	$1,701,221	$7,077,114	$894,704	$549,820
Oct-09	$405,037	$2,136	$2,320,472	$11,003,375	$553,038	$483,214
Nov-09	$109,713	$6,171	$1,113,913	$7,288,862	$568,942	$37,264
Dec-09	$3,259,547	$81,790	$173,475	$15,070,034	$1,341,044	$272,917
Jan-10	$6,213,523	$164,034	$1,408,756	$24,669,068	$980,832	$551,706
Feb-10	$3,787,129	$71,112	$1,192,894	$10,932,772	$1,085,923	$573,703
Mar-10	$1,149,901	$55,004	$2,480,550	$7,598,771	$1,537,198	$850,687
Apr-10	$1,373,143	$127,499	$2,488,915	$11,937,201	$721,388	$387,016
May-10	$1,655,979	$7,462,340	$1,320,404	$11,351,038	$1,248,001	$345,411
Jun-10	$2,830,020	$20,571,439	$229,942	$11,108,209	$2,860,370	$1,174,841

In mid May, maintenance work began on a 230kV line in the eastern region of the RTO. This transmission outage, coupled with higher average loads due to high temperatures in the region and the physical characteristics and operating parameters of these units, required certain units to operate continuously in order to maintain system reliability. This continuous operation required a significant payment of balancing operating reserve credits to cover the offers of the units, given that LMP did not result in adequate revenues. Physical operating parameters, such as minimum run times and minimum down times, can have a significant impact on such credits when they result in a unit operating during uneconomic hours. The balancing operating reserve credits paid to these units were allocated to real-time load and exports.

One of the purposes of the modified Operating Reserve Business Rules was the reallocation of reliability charges to those requiring additional resources to maintain system reliability, defined to be real-time load and exports. In the first six months of 2010, the rule change had a significant impact on the categorization and corresponding allocation of balancing operating reserve charges. In the first half of 2010, $54,057,630 of reliability charges, which included $28,033,779 of Eastern reliability credits in May and June, were allocated to participants serving real-time load and exports, which would have been charged to supply, demand, and generator deviations under the prior rules.

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.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Market.** During the first six months of 2010, PJM was a net exporter of energy in the Real-Time Market in all months. In the Real-Time Market, monthly net interchange averaged -559 GWh.[1] Gross monthly import volumes averaged 3,509 GWh while gross monthly exports averaged 4,068 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market.** During the first six months of 2010, PJM was a net exporter of energy in the Day-Ahead Market in all months. In the Day-Ahead Market, monthly net interchange averaged -915 GWh. Gross monthly import volumes averaged 5,716 GWh while gross monthly exports averaged 6,631 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** During the first six months of 2010, gross imports in the Day-Ahead Energy Market were 163 percent of the Real-Time Market's gross imports (111 percent for the calendar year 2009), gross exports in the Day-Ahead Market were 163 percent of the Real-Time Market's gross exports (127 percent for the calendar year 2009) and net interchange in the Day-Ahead Energy Market was 164 percent of net interchange in the Real-Time Energy Market (-3,356 GWh in the Real-Time Market and -5,490 GWh in the Day-Ahead Market).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market, during the first six months of 2010, there were net exports at 12 of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Market accounted for 73 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 39 percent, PJM/Neptune (NEPT) with 27 percent and PJM/First Energy Corporation (FE) with 7 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 73 percent of the total net PJM exports in the Real-Time Market. Seven PJM interfaces had net imports, with two importing interfaces accounting for 73 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 60 percent and PJM/Michigan Electric Coordinated System (MECS) with 13 percent.[2]

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, during the first six months of 2010, there were net exports at 13 of PJM's 21 interfaces. The top four net exporting interfaces accounted for 83 percent of the total net exports: PJM/western Alliant Energy Corporation (ALTW) with 35 percent, PJM/NYIS with 18 percent, PJM/MidAmerican Energy Company (MEC) with 16 percent and PJM/NEPT with 14 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 32 percent of the total net PJM exports in the Day-Ahead Market.[3] Eight PJM interfaces had net imports in the Day-Ahead Market, with two interfaces accounting for 81 percent of the total net imports: PJM/OVEC with 48 percent and PJM/Michigan Electric Coordinated System (MECS) with 34 percent.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** During the first six months of 2010, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO. Over the first six months of 2010, the PJM average hourly

1 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.

2 In the Real-Time Market, two PJM interfaces had a net interchange of zero.

3 The Linden Interface accounted for less than 1 percent of the total net exports in the Day-Ahead Market during the first six months of 2010.

Locational Marginal Price (LMP) at the PJM/MISO border was $33.77 while the Midwest ISO LMP at the border was $33.87, a difference of $0.10. While the average hourly flow reflected imports into PJM from the Midwest ISO, further analysis of hourly interchange showed patterns of expected market participant response that created price convergence at the PJM/MISO Interface.

- **PJM and New York ISO Interface Prices.** During the first six months of 2010, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus reflected economic fundamentals, as did the relationship between interface price differentials and power flows between PJM and the NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and the NYISO. Over the first six months of 2010, the PJM average hourly LMP at the PJM/NYISO border was $45.16 while the NYISO LMP at the border was $43.16, a difference of $2.00. While the average hourly flow reflected exports from PJM into the NYISO, further analysis of hourly interchange shows patterns of expected market participant response that created price convergence at the PJM/NYISO Interface.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[4] On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes 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 the NYISO began discussion of a market based congestion management protocol, which continued during the first six months of 2010. By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[5]

  After working in collaboration with PJM, the Midwest ISO and the Ontario Independent Electricity System Operator (IESO), including an opportunity to comment by stakeholders and market monitors, the NYISO filed on January 12, 2010, a *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.*[6] On July 15, 2010, the Commission conditionally accepted the NYISO Report subject to the parties filing answers to the questions set forth in the order within 30 days of the date of the order.[7] The Commission requested that the parties provide additional evidence regarding the proposed solutions. Intervenors, including the MMU, will be permitted to submit comments addressing those submissions 30 days thereafter.

- **PJM and Midwest ISO 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 2010. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates, allow for redispatch of the PJM and MISO regions as if they were one large control area. The MMU believes that this approach should be the industry standard. This conceptual achievement, however, has not been matched by adequate attention to the details of its administration.

  The market based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[8] In 2009, the Midwest ISO requested that PJM review the components of the CMP to verify data accuracy. During this review, it was found that some data inputs to the market flow calculator were incorrect during the time period from April 2005 through June 2009. The resulting inaccuracies in the market flow calculation meant that the Midwest ISO received less compensation than appropriate. While the errors in input data have been corrected for market to market activity moving forward, the Midwest ISO and PJM are currently in the process of calculating the shortfall. PJM reported an estimate of 77.5 million dollars.[9] On March 8, 2010, after the settlement discussions mediated by the Federal Energy Regulatory Commission (FERC)

4 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

5 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

6 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (January 12, 2010) (Accessed April 22, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

7 132 FERC ¶61,031.

8 See PJM. "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,294 KB).

9 See PJM. "PJM/MISO Market Flow Calculation Error"(September 10, 2009) (Accessed April 22, 2010) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

ended, the Midwest ISO filed complaints with FERC against PJM.[10] On April 12, 2010, PJM answered and filed a counter complaint.[11] These matters are now pending before the Commission in settlement proceeding.[12] The MMU remains concerned that this disagreement over administration of the JOA will unduly detract from its ability to serve as the basis for moving forward industry practice for managing congestion and loop flows at system interfaces, but notes that the *Memorandum of Understanding* signed by PJM and the Midwest ISO on May 27, 2010 "reaffirms the value of the agreement and pledges continued cooperation to develop new practices to improve the interface between the two organizations"[13].

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[14] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through the first six months of 2010.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[15] 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 through the first six months of 2010. As part of this agreement, both parties agreed to develop a formal CMP. On February 2, 2010, PJM and PEC filed a revision to the JOA to include a Congestion Management Protocol.[16] The MMU responded to the filing on February 23, 2010.[17] The MMU response noted that the agreement included discriminatory treatment for the identified transactions with respect to access to ATC, that a regional approach is preferable to entering into agreements with individual neighbors, and that a sunset should be required in order to ensure that the next step towards such regional coordination is taken without delay. PJM and PEC filed an answer on March 10, 2010, to which the MMU responded on April 2, 2010. PJM and PEC filed an additional answer on April 19, 2010.[18] On May 28, 2010, the Commission conditionally approved the revised PJM/PEC JOA.[19] PJM and PEC were required to make a compliance filing within thirty days of the date of the order answering specific questions related to the impact of the dynamic scheduling arrangement on NERC standards and discriminatory access, the market pricing mechanisms with regards to eliminating the nuclear and hydro units from the calculation and the discriminatory use of export make whole payments under this agreement. On June 28, 2010, PJM and PEC filed their response.[20] The MMU responded to the compliance filing on July 19, 2010, reiterating the argument that the PJM/PEC JOA provides for preferential treatment to ATC and that the elimination of nuclear and hydro units from the interface price calculation is not consistent with the economics of locational marginal pricing.[21]

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[22] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC Southeastern Electric Reliability Council (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 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 2010, PJM continued to operate under the terms of the operating protocol developed in 2005.[23] The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service, but 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

10 Complaints of the Midwest Independent Transmission System Operator, Inc., filed Dockets Nos. EL10-45-000 & EL10-46-000 (respectively, MISO Complaint I and MISO Complaint II).
11 Complaint of PJM Interconnection, L.L.C., filed in EL10-60-000 at 19.
12 131 FERC ¶61,284 (June 29, 2010).
13 See PJM. "PJM-MISO-MOU-May-2010" (May 27, 2010) (Accessed June 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pjm-miso-mou-may-2010.ashx> (313 KB).
14 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).
15 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2,983 KB).
16 See PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).
17 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010) (Accessed April 21, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Motion_to_Intervene_and_Comments_ER10-713-000_20100225.pdf> (225 KB).
18 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM; Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc., in Docket No. ER10-713-000.
19 See Docket No. ER10-713-000. Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Progress Energy Carolinas.
20 See PJM/PEC compliance filing in Docket No. ER10-713-002.
21 See IMM response to PJM/PEC compliance filing in Docket No. ER10-713-002.
22 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).
23 111 FERC ¶ 61,228 (2005).

Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In the first six months of 2010, PSE&G's FTR credits were $154,636 less than the congestion charges because, for the entire PJM FTR Market, revenue was insufficient to fully fund FTRs. Under the FERC order, Con Edison receives credits, on an hourly basis, for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In the first six months of 2010, Con Edison's congestion credits were less than the associated congestion charges by approximately $1.2 million.

In effect, Con Edison has been given congestion credits that are equivalent to a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. During the first six months of 2010, Con Edison's negative congestion credits would have been approximately $10,000.

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in six percent of the hours during the first six months of 2010.

On February 23, 2009, PJM filed a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[24] After NRG and FERC trial staff contested the settlement, the Commission found that the record does not sufficiently address "threshold issues" concerning the rollover of these contracts, including the impact on locational marginal pricing, and whether this result would be unduly discriminatory.[25] The Commission has required the parties to brief these issues and has reserved the right to establish additional procedures if these briefs raise material issues of disputed fact.[26]

24 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

25 130 FERC ¶61,126 at PP 1,24 (February 19, 2010) ("The parties need to address whether these contracts are sufficiently firm to be rolled over under Order No. 888; whether, if they are eligible for rollover, Con Ed is eligible only for OATT service, or whether the circumstances here warrant a non-conforming agreement; and whether and what effect these agreements have on the rights of and prices paid by other parties, including the effect of the flow changes in the JOA on the Locational Marginal Prices in both PJM and NYISO and the effect of these provisions on the ability of other parties to transact business.").

26 *Id.*

The MMU has reviewed the briefs filed in this proceeding on April 21, 2010, and believes that they raise questions about whether allowing rollover is appropriate.[27] There is reason for concern that continuing these agreements may interfere with the efficient management of the NYISO/PJM seam, accord preferential access to transmission service and limit security constrained least cost dispatch. Moreover, no offsetting reliability consideration has been identified and explained. On May 11, 2010, the MMU offered comments on the issues raised by the Commission, noting that "the settling parties fail to demonstrate any circumstances that may now exist warranting a non-conforming agreement under the current approach to seams management, nor do they attempt to explain how such circumstances would continue to exist under the reforms to be implemented through the Broader Regional Markets Initiative." Additionally, "the settling parties have failed to show that continuation of the grandfathered transmission service agreements will neither interfere with the efficient calculation of LMPs in both PJM and the NYISO, and at their interface, nor harm the ability of parties to efficiently transact business".[28]

- **Neptune Underwater Transmission Line to Long Island, New York.** On July 1, 2007, a 65-mile direct current (DC) transmission line from Sayreville, New Jersey, to Nassau County on Long Island, via undersea and underground cable, was placed in service, providing a direct connection from PJM to the New York Independent System Operator, Inc. (NYISO). This is a merchant 230 kV transmission line 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.[29] The basis for this limitation is unclear. Over the first six months of 2010, the PJM average hourly LMP at the Neptune Interface was $47.71 while the NYISO LMP at the Neptune Bus was $56.68, a difference of $8.97. The average hourly flow during the first six months of 2010 was -586 MW, which aligned with price differentials in only 60 percent of all hours during the first six months of 2010.

- **Linden Variable Frequency Transformer (VFT) Facility.** On November 1, 2009, the Linden VFT facility was placed in service, providing an additional direct connection from PJM to the NYISO. A variable frequency transformer allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle

27 See, e.g., Initial Brief in Response to Order Establishing Additional Procedures of the NRG Companies, filed in Docket No. ER08-858-000, et al.

28 See Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al.

29 See PJM. "PJM Open Access Transmission Tariff" (July 21, 2010) (Accessed August 7, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,403 KB).

regulating transformer.[30] The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line, with a capacity of 300 MW. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[31] The basis for this limitation is unclear. Over the first six months of 2010, the PJM average hourly LMP at the Linden Interface was $47.74 while the NYISO LMP at the Linden Bus was $51.07, a difference of $3.33. The average hourly flow during the first six months of 2010 was -148 MW, which aligned with price differentials in only 56 percent of all hours during the first six months of 2010.

Interchange Transaction Issues

- **Loop Flows.** Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. Loop flows arise from transactions on contract paths that do not correspond to the actual physical paths that the energy takes. During the first six months of 2010, net scheduled interchange was -2,307 GWh and net actual interchange was -2,132 GWh for a difference of 175 GWh or 7.6 percent (3.3 percent for the first six months of 2009). The net totals in the first three months of 2010 reflected a large mismatch between scheduled and actual interchange (21.4 percent). An evaluation of the monthly net flows showed that the values had been converging. As the net scheduled export levels increased in the second quarter of 2010, the year to date net difference, as a percentage of the year to date scheduled interchange decreased. A similar pattern was observed in the first quarter of 2007, when the net scheduled interchange changed from net exports to net imports, reducing the net scheduled interchange, and increasing the net difference, resulting in a difference between scheduled and actual interchange of 49.4 percent. 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 2009, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-7,667 GWh during the first six months of 2010 and -7,563 GWh during the first six months of 2009). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (1,954 GWh during the first six months of 2010 and 1,827 GWh during the first six months of 2009). 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 (PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) to the west and PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK to the east) was significant during the first six months of 2010.

  The southern interfaces have historically experienced significant loop flows.[32] A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP). At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. (The average difference between the Locational Marginal Price (LMP) at the Southeast pricing points and the SouthEXP pricing point was $4.26 during the first six months of 2010 and the average difference between LMP at the Southwest pricing points and the SouthEXP pricing point was -$2.97 during the first six months of 2010. In other words, it was more expensive to buy from PJM, for export to the south, using the old Southeast pricing point as opposed to the current SouthEXP pricing point, and less expensive to buy from PJM, for export to the south, using the old Southwest pricing point as opposed to the current SouthEXP

30 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.

31 See PJM. "PJM Open Access Transmission Tariff" (July 21, 2010) (Accessed August 7, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,884 KB).

32 See *2002 State of the Market Report,* Part 2, Section 3, "Interchange Transactions." (March 5, 2003) (Accessed April 22, 2010) <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2002/SOM2002-part2.pdf> (4,068 KB).

pricing point.) These grandfathered agreements remain in place. The MMU recommends that these agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

- **PJM Transmission Loading Relief Procedures (TLRs).** During the first six months of 2010, PJM issued 58 TLRs. Of the 58 TLRs issued, the highest levels reached were TLR 3a for 33 events and TLR 3b for the remaining 25 events. Figure 4-22 shows that there was an increase in the number of TLRs issued by PJM in June 2010. The increase in TLRs, as well as the increase in the total MWh of curtailed transactions resulting from those TLRs, was primarily the result of increased weather related load. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. There are several factors that affect the number of times a reliability coordinator needs to initiate a TLR and the TLR level, including market design and operating agreements. The fact that PJM has issued only 58 TLRs during the first six months of 2010, compared to 90 during the first six months of 2009, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with the Midwest ISO. 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.

- **Up-To Congestion.** In the period following the March 1, 2008 modifications to the up-to congestion bids (March 1, 2008 through June 30, 2010), the monthly average of up-to congestion bidding increased from 3,027.1 GWh (for the period from January 1, 2006 through April 30, 2008) to 5,054.2 GWh. In June 2010, a single market participant submitted a large quantity of up-to congestion bids. The activities of this one participant accounted for the significant increase in total up-to congestion MWh as shown in Figure 4-23.

  The up-to congestion transactions during the first six months of 2010 were comprised of 47.3 percent imports, 49.5 percent exports and 3.2 percent wheeling transactions. Only 0.2 percent of the up-to congestion transactions had matching Real-Time Market transactions. Of the up-to congestion transactions with matching Real-Time Market transactions, 0.1 percent were imports, 95.9 percent were exports and 4.0 percent were wheel through transactions.

  When the up-to congestion product was used as intended, with matching Real-Time Market transactions, 79.4 percent of the total cleared transaction MW were profitable during the first six months of 2010. The net profit on all these transactions was approximately $357,000. When up-to congestion transactions did not have a matching Real-Time Market transaction, 56.7 percent of the total cleared transaction MW were profitable. The net loss on all these transactions was approximately $26.5 million.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** When reserving non-firm transmission, the market participant has 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.

  If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction.

  Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. The method that PJM uses to curtail not willing to pay congestion requires the transaction to be loaded. While loaded, if congestion occurs for a not willing to pay congestion transaction, a message is sent to the PJM operators requesting the transaction be curtailed at the next 15 minute interval.

  The total uncollected congestion charges for the first six months of 2010 were approximately $1.2 Million ($62,764 for the first six months of 2009). The increase in uncollected congestion charges has been caused by an increase in market participant use of not willing to pay congestion transmission on their energy transactions in 2010. The MMU recommended modifying the evaluation criteria via a change to PJM's market software, to ensure that a not willing to pay congestion transaction is not permitted to flow in the presence of congestion. A change to PJM's EES application is currently in development that will evaluate transactions, which have not willing to pay congestion transmission reservations associated with them, that are either flowing or are about to start. Those transactions will be compared to LMP data to determine whether they should be curtailed (if already flowing) or prevented from starting. The EES modifications are expected to be released into production in the third quarter of 2010.

- **Elimination of Sources and Sinks.** The MMU has recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time 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.

  The issue of uncollected congestion from not willing to pay congestion transmission reservations would also be mitigated by the elimination of internal sources and sinks from the Real-Time PJM Energy Market. Because only interfaces would be permitted to be specified as a valid source and sink on an external energy transaction, the only opportunity for congestion exposure would be for wheeling transactions, as all external imports and exports would have the source and sink specified as the same bus (i.e. the interface where the transaction enters or leaves the PJM Market) which, by definition, would represent no congestion exposure.

  Until the internal source and sink designations are eliminated from the external energy transactions in the Day-Ahead Energy Market, the MMU continues to recommend that PJM require that all import and export up-to congestions transactions pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserve charges.

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.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities for the first six months of 2010, including evolving transaction patterns, economics and issues. During the first six months of 2010, PJM was a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 73 percent of the total real-time net exports and two interfaces accounted for 73 percent of the real-time net import volume. Four interfaces accounted for 83 percent of the total day-ahead net exports and two interfaces accounted for 81 percent of the day-ahead net import volume.

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 2010 (See 2009 SOM, Figure 4-1)

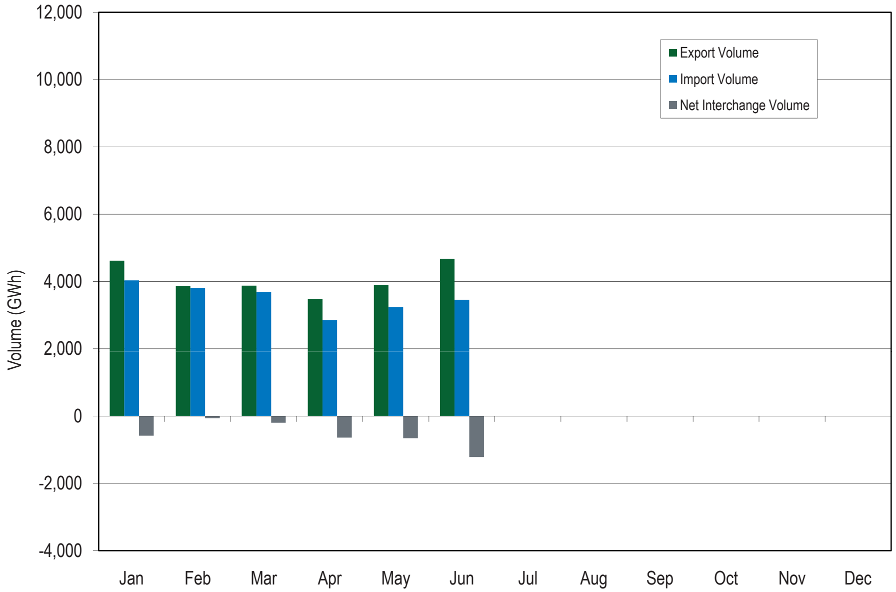


Figure 4-2 PJM day-ahead scheduled imports and exports: January through June 2010 (See 2009 SOM, Figure 4-2)

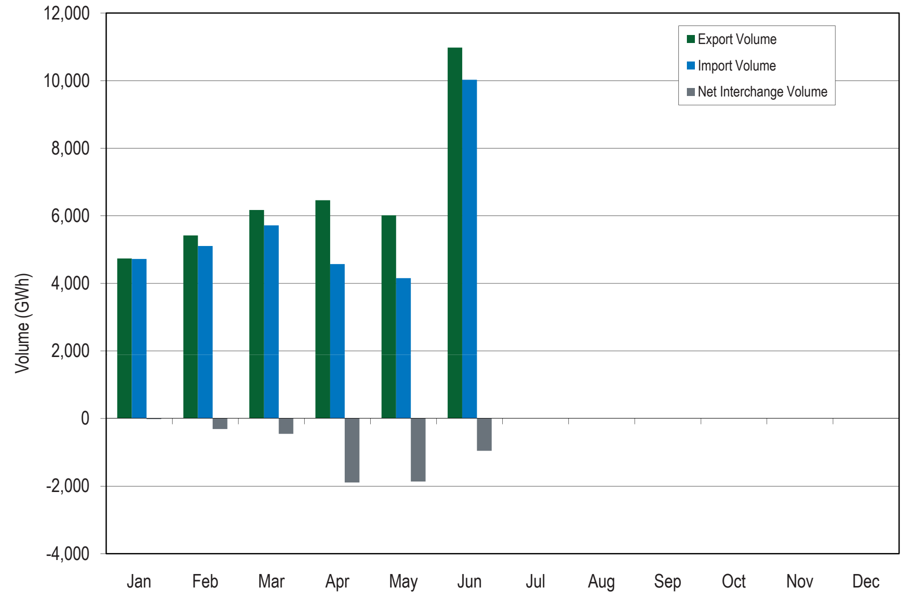
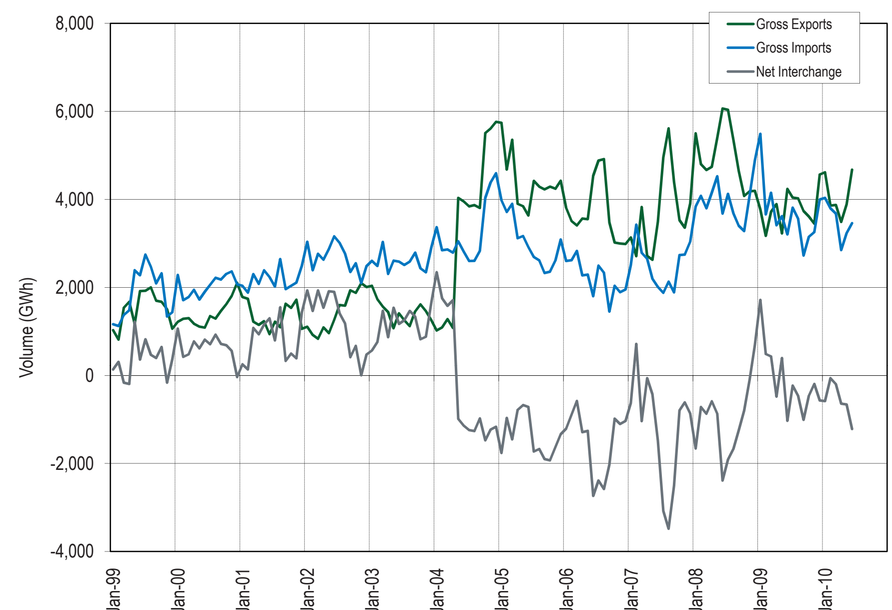


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through June 2010 (See 2009 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through June 2010 (See 2009 SOM, Table 4-1)

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	(70.4)	(72.8)	(40.8)	(141.2)	(114.0)	(154.2)	(593.4)
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	219.7	92.2	(32.8)	(22.9)	123.6	(116.4)	263.4
EKPC	(65.5)	(99.2)	14.1	39.3	(0.2)	(19.5)	(131.0)
LGEE	31.9	144.5	29.7	44.1	116.8	130.0	497.0
MEC	(454.2)	(422.0)	(458.1)	(383.0)	(436.0)	(429.4)	(2,582.7)
MISO	(74.1)	512.4	510.7	8.1	188.5	(327.7)	817.9
ALTE	3.6	(9.5)	13.7	(7.1)	(0.7)	(66.2)	(66.2)
ALTW	(32.1)	(8.4)	1.4	(16.1)	(27.7)	(148.3)	(231.2)
AMIL	(141.6)	(85.5)	(63.5)	(25.6)	37.1	18.8	(260.3)
CIN	78.4	323.4	233.5	(112.2)	189.0	155.8	867.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	(117.4)	(60.2)	(70.6)	(114.3)	(142.5)	(173.5)	(678.5)
IPL	(28.4)	48.4	(4.6)	112.6	61.3	(61.2)	128.1
MECS	195.1	312.7	387.5	199.7	95.9	103.2	1,294.1
NIPS	(24.0)	(10.8)	(4.9)	(0.6)	(1.9)	(111.1)	(153.3)
WEC	(7.7)	2.3	18.2	(28.3)	(22.0)	(45.2)	(82.7)
NYISO	(1,307.0)	(1,039.9)	(1,109.6)	(950.3)	(1,334.9)	(1,257.1)	(6,998.8)
LIND	(146.0)	(125.5)	(115.7)	(75.8)	(89.8)	(100.4)	(653.2)
NEPT	(496.7)	(423.6)	(449.9)	(280.9)	(464.8)	(466.6)	(2,582.5)
NYIS	(664.3)	(490.8)	(544.0)	(593.6)	(780.3)	(690.1)	(3,763.1)
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	5,800.5
TVA	(39.0)	(121.5)	(129.3)	(88.3)	(7.8)	(43.4)	(429.3)
Total	(581.7)	(63.3)	(197.3)	(640.2)	(658.1)	(1,215.8)	(3,356.4)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through June 2010 (See 2009 SOM, Table 4-2)

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	128.3	113.4	99.8	0.6	22.7	9.9	374.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	408.5	235.2	135.1	142.6	258.6	174.8	1,354.8
EKPC	15.8	3.0	53.9	58.1	34.8	36.6	202.2
LGEE	48.9	150.5	73.5	58.7	135.6	161.8	629.0
MEC	44.1	28.1	35.7	52.3	61.5	34.7	256.4
MISO	1,142.9	1,388.4	1,292.1	852.6	907.3	1,055.0	6,638.3
ALTE	30.0	8.0	28.9	2.4	9.4	1.0	79.7
ALTW	0.0	5.4	7.6	1.1	2.8	6.3	23.2
AMIL	23.5	49.2	39.2	45.6	55.0	37.1	249.6
CIN	500.9	555.4	454.8	227.2	364.7	551.6	2,654.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	181.6	207.6	205.4	156.0	147.5	162.3	1,060.4
IPL	47.1	116.7	16.2	115.9	113.5	71.8	481.2
MECS	304.3	385.9	475.1	283.7	181.5	185.2	1,815.7
NIPS	0.0	0.0	0.0	0.2	13.4	6.4	20.0
WEC	55.5	60.2	64.9	20.5	19.5	33.3	253.9
NYISO	934.4	901.2	922.5	765.7	890.8	916.1	5,330.7
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	934.4	901.2	922.5	765.7	890.8	916.1	5,330.7
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	5,800.5
TVA	134.6	35.7	47.7	63.0	115.6	67.9	464.5
Total	4,034.4	3,798.5	3,679.1	2,847.6	3,232.8	3,458.7	21,051.1

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through June 2010 (See 2009 SOM, Table 4-3)

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	198.7	186.2	140.6	141.8	136.7	164.1	968.1
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	188.8	143.0	167.9	165.5	135.0	291.2	1,091.4
EKPC	81.3	102.2	39.8	18.8	35.0	56.1	333.2
LGEE	17.0	6.0	43.8	14.6	18.8	31.8	132.0
MEC	498.3	450.1	493.8	435.3	497.5	464.1	2,839.1
MISO	1,217.0	876.0	781.4	844.5	718.8	1,382.7	5,820.4
ALTE	26.4	17.5	15.2	9.5	10.1	67.2	145.9
ALTW	32.1	13.8	6.2	17.2	30.5	154.6	254.4
AMIL	165.1	134.7	102.7	71.2	17.9	18.3	509.9
CIN	422.5	232.0	221.3	339.4	175.7	395.8	1,786.7
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	299.0	267.8	276.0	270.3	290.0	335.8	1,738.9
IPL	75.5	68.3	20.8	3.3	52.2	133.0	353.1
MECS	109.2	73.2	87.6	84.0	85.6	82.0	521.6
NIPS	24.0	10.8	4.9	0.8	15.3	117.5	173.3
WEC	63.2	57.9	46.7	48.8	41.5	78.5	336.6
NYISO	2,241.4	1,941.1	2,032.1	1,716.0	2,225.7	2,173.2	12,329.5
LIND	146.0	125.5	115.7	75.8	89.8	100.4	653.2
NEPT	496.7	423.6	449.9	280.9	464.8	466.6	2,582.5
NYIS	1,598.7	1,392.0	1,466.5	1,359.3	1,671.1	1,606.2	9,093.8
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	173.6	157.2	177.0	151.3	123.4	111.3	893.8
Total	4,616.1	3,861.8	3,876.4	3,487.8	3,890.9	4,674.5	24,407.5

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through June 2010 (See 2009 SOM, Table 4-4)

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	(89.3)	(111.3)	(114.7)	(122.2)	(108.3)	(134.2)	(680.0)
CPLW	10.2	(1.0)	1.0	(0.9)	(1.0)	(1.5)	6.8
DUK	161.4	38.4	8.6	12.6	72.5	23.2	10.8
EKPC	(1.5)	(5.9)	(3.4)	(0.2)	(1.4)	(3.0)	(60.1)
LGEE	1.0	5.3	0.0	(0.1)	1.4	(8.0)	(30.9)
MEC	(479.4)	(444.1)	(482.8)	(433.0)	(464.1)	(789.0)	(3,126.4)
MISO	282.3	(160.5)	(312.1)	(1,450.5)	(1,018.5)	550.4	(2,108.9)
ALTE	227.6	(257.5)	(136.2)	(302.4)	(711.0)	(168.0)	(1,347.5)
ALTW	(282.2)	(414.3)	(1,220.9)	(1,761.3)	(766.8)	(2,195.9)	(6,641.4)
AMIL	14.4	97.5	6.7	12.4	44.5	114.6	290.1
CIN	182.9	(60.8)	43.1	(70.3)	41.8	310.0	446.7
CWLP	0.0	0.0	0.0	0.0	(0.3)	0.0	(0.3)
FE	(70.5)	(20.7)	118.8	(72.4)	(79.3)	390.4	266.3
IPL	(53.4)	(18.4)	(44.7)	(8.5)	(42.0)	68.9	(98.1)
MECS	387.8	654.4	885.6	732.9	546.6	1,223.9	4,431.2
NIPS	(204.5)	(217.0)	(143.3)	(87.6)	(120.2)	(103.9)	(876.5)
WEC	80.2	76.3	178.8	106.7	68.2	910.4	1,420.6
NYISO	(969.0)	(912.0)	(825.4)	(752.7)	(1,017.9)	(1,657.9)	(6,134.9)
LIND	(21.1)	(18.3)	(53.2)	(11.4)	(15.3)	(12.0)	(131.3)
NEPT	(502.6)	(445.2)	(456.7)	(301.3)	(473.4)	(472.7)	(2,651.9)
NYIS	(445.3)	(448.5)	(315.5)	(440.0)	(529.2)	(1,173.2)	(3,351.7)
OVEC	1,074.0	1,243.3	1,300.5	917.1	679.0	1,058.2	6,272.1
TVA	(5.3)	37.8	(27.0)	(60.9)	(5.4)	7.7	(53.1)
Total	(15.6)	(310.0)	(455.3)	(1,890.8)	(1,863.7)	(954.1)	(5,489.5)

Table 4-5 Day-ahead gross import volume by interface (GWh): January through June 2010 (See 2009 SOM, Table 4-5)

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	64.2	39.5	29.3	10.7	15.8	49.1	208.6
CPLW	15.6	0.6	1.8	0.0	1.4	0.8	20.2
DUK	176.3	96.2	48.1	40.2	107.2	77.8	545.8
EKPC	0.0	0.0	0.4	0.0	0.0	0.0	0.4
LGEE	1.0	5.4	0.0	0.0	1.8	0.5	8.7
MEC	18.8	5.6	12.2	18.6	70.2	158.8	284.2
MISO	2,400.5	2,738.3	3,112.5	2,678.8	2,251.6	7,455.1	20,636.8
ALTE	866.4	762.4	662.8	382.9	263.8	721.2	3,659.5
ALTW	72.0	67.2	72.4	53.6	40.2	345.7	651.1
AMIL	68.1	157.9	50.5	32.1	44.8	114.6	468.0
CIN	436.8	592.0	555.1	590.4	430.6	969.6	3,574.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	156.2	176.9	364.9	203.7	179.3	752.7	1,833.7
IPL	26.9	29.4	30.7	102.8	97.0	1,045.3	1,332.1
MECS	606.2	801.7	1,125.2	1,118.7	1,035.2	2,223.8	6,910.8
NIPS	28.6	19.5	24.3	33.1	26.9	292.1	424.5
WEC	139.3	131.3	226.6	161.5	133.8	990.1	1,782.6
NYISO	835.3	885.1	1,095.7	883.7	858.1	1,165.0	5,722.9
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	835.3	885.1	1,095.7	883.7	858.1	1,165.0	5,722.9
OVEC	1,133.2	1,259.7	1,379.9	922.0	802.1	1,063.8	6,560.7
TVA	75.9	77.8	36.7	15.2	44.4	55.3	305.3
Total	4,720.8	5,108.2	5,716.6	4,569.2	4,152.6	10,026.2	34,293.6

Table 4-6 Day-ahead gross export volume by interface (GWh): January through June 2010 (See 2009 SOM, Table 4-6)

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	153.5	150.8	144.0	132.9	124.1	183.3	888.6
CPLW	5.4	1.6	0.8	0.9	2.4	2.3	13.4
DUK	14.9	57.8	39.5	27.6	34.7	54.6	535.0
EKPC	1.5	5.9	3.8	0.2	1.4	3.0	60.5
LGEE	0.0	0.1	0.0	0.1	0.4	8.5	39.6
MEC	498.2	449.7	495.0	451.6	534.3	947.8	3,410.6
MISO	2,118.2	2,898.8	3,424.6	4,129.3	3,270.1	6,904.7	22,745.7
ALTE	638.8	1,019.9	799.0	685.3	974.8	889.2	5,007.0
ALTW	354.2	481.5	1,293.3	1,814.9	807.0	2,541.6	7,292.5
AMIL	53.7	60.4	43.8	19.7	0.3	0.0	177.9
CIN	253.9	652.8	512.0	660.7	388.8	659.6	3,127.8
CWLP	0.0	0.0	0.0	0.0	0.3	0.0	0.3
FE	226.7	197.6	246.1	276.1	258.6	362.3	1,567.4
IPL	80.3	47.8	75.4	111.3	139.0	976.4	1,430.2
MECS	218.4	147.3	239.6	385.8	488.6	999.9	2,479.6
NIPS	233.1	236.5	167.6	120.7	147.1	396.0	1,301.0
WEC	59.1	55.0	47.8	54.8	65.6	79.7	362.0
NYISO	1,804.3	1,797.1	1,921.1	1,636.4	1,876.0	2,822.9	11,857.8
LIND	21.1	18.3	53.2	11.4	15.3	12.0	131.3
NEPT	502.6	445.2	456.7	301.3	473.4	472.7	2,651.9
NYIS	1,280.6	1,333.6	1,411.2	1,323.7	1,387.3	2,338.2	9,074.6
OVEC	59.2	16.4	79.4	4.9	123.1	5.6	288.6
TVA	81.2	40.0	63.7	76.1	49.8	47.6	358.4
Total	4,736.4	5,418.2	6,171.9	6,460.0	6,016.3	10,980.3	39,783.1

Interface Pricing

Table 4-7 Active interfaces: January through June 2010 (See 2009 SOM, Table 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 4-4 PJM's footprint and its external interfaces (See 2009 SOM, Figure 4-4)

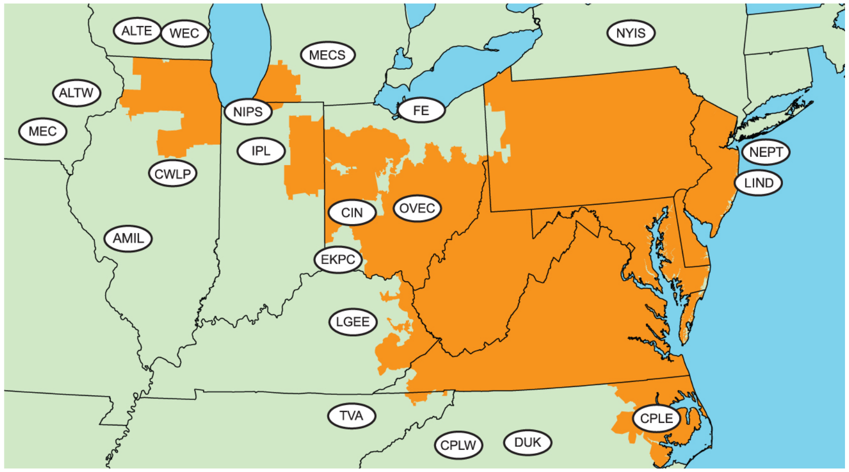


Table 4-8 Active pricing points: January through June 2010 (See 2009 SOM, Table 4-8)

PJM 2010 Pricing Points (January through June)			
LIND	MICHFE	MISO	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO
OVEC	SOUTHEXP	SOUTHIMP	

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

PJM and Midwest ISO Interface Prices

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): January through June 2010 (See 2009 SOM, Figure 4-5)

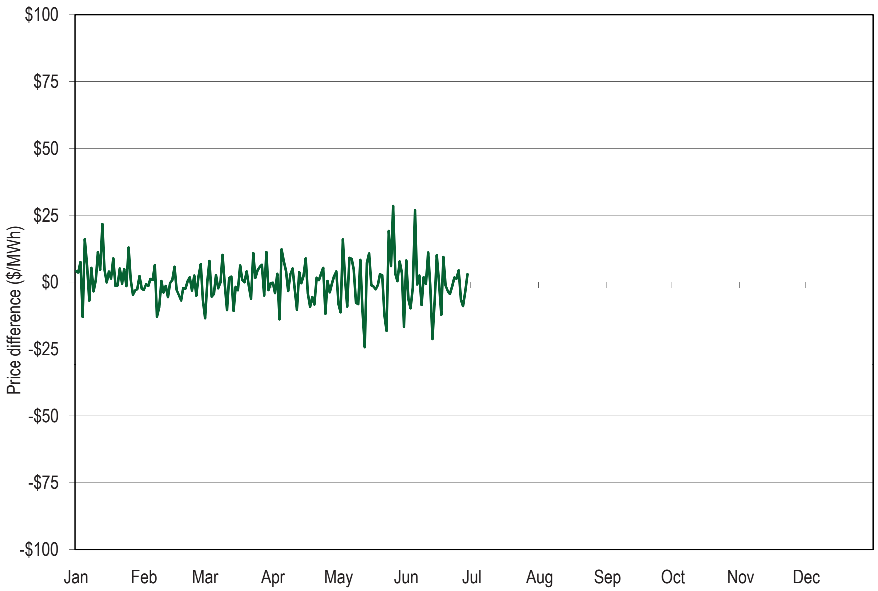


Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through June 2010 (See 2009 SOM, Figure 4-6)

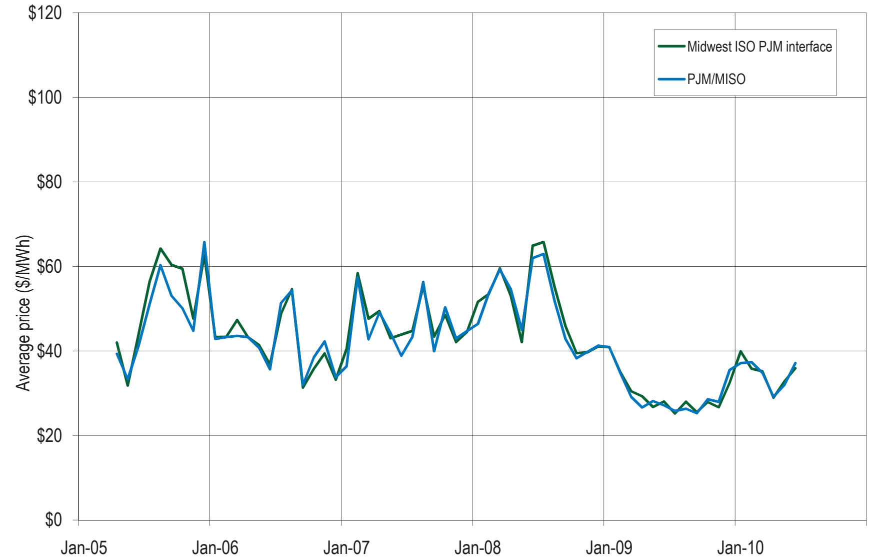


Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): January 2008 through June 2010 (See 2009 SOM, Table 4-9)

	2008			2009			2010		
	LMP	MCC	MLC	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$8.26	($6.56)	($2.86)	$4.81	($2.65)	($2.06)	$2.97	($4.89)	($2.54)
Beaver Valley (PJM) & Mansfield (MISO)	$0.89	($14.42)	($2.38)	$3.22	($4.92)	($1.38)	$1.98	($6.64)	($1.79)
Miami Fort (PJM) & (MISO)	$1.25	($12.27)	($4.16)	$2.20	($4.64)	($2.70)	$1.68	($5.48)	($3.24)
Stuart (PJM) & (MISO)	$0.87	($12.04)	($4.77)	$1.81	($4.63)	($3.07)	$1.57	($5.22)	($3.62)
PJM/MISO Interface	($1.16)	($15.34)	($3.51)	$0.01	($6.94)	($2.58)	($0.10)	($7.36)	($3.14)
LMP: Locational Marginal Price, MCC: Marginal Congestion Component, MLC: Marginal Loss Component									

Figure 4-7 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): January through June 2010 (See 2009 SOM, Figure 4-7)

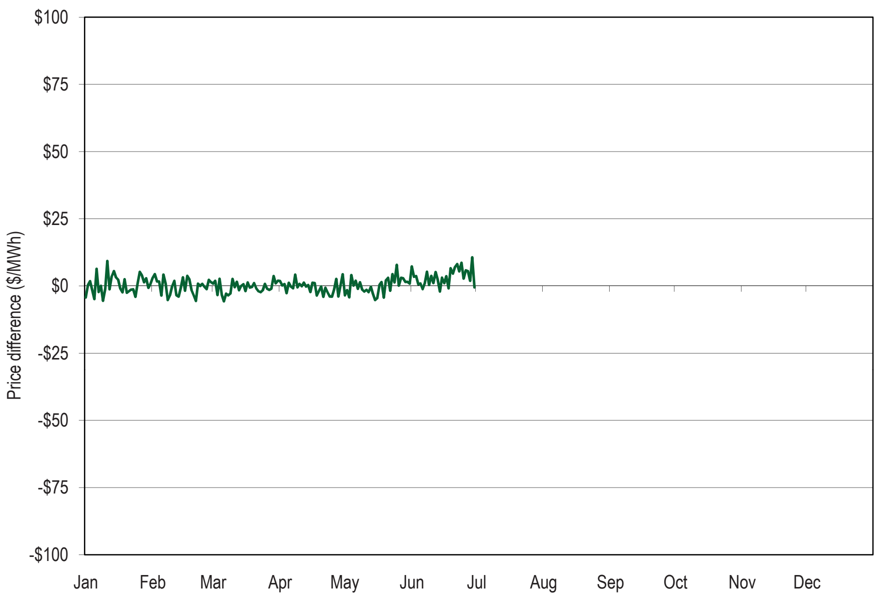


Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through June 2010 (See 2009 SOM, Table 4-8)

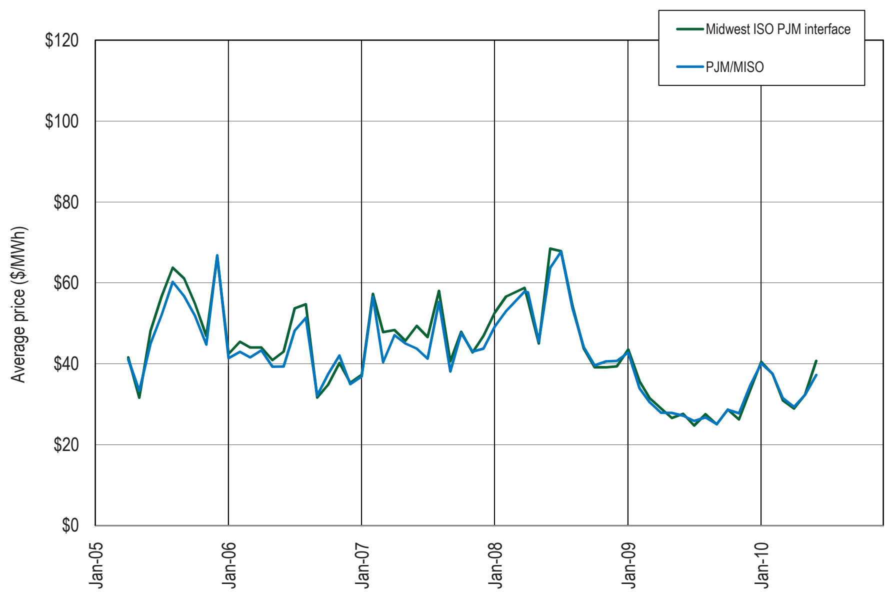


Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): January 2008 through June 2010 (See 2009 SOM, Table 4-10)

	2008			2009			2010		
	LMP	MCC	MLC	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$9.19	($3.00)	($4.25)	$4.02	($2.06)	($2.80)	$1.77	($4.90)	($2.99)
Beaver Valley (PJM) & Mansfield (MISO)	$3.40	($9.88)	($3.16)	$2.48	($4.72)	($1.67)	$1.63	($5.86)	($2.16)
Miami Fort (PJM) & (MISO)	($0.05)	($11.17)	($5.32)	$1.87	($3.85)	($3.16)	$0.66	($4.99)	($4.00)
Stuart (PJM) & (MISO)	($0.56)	($11.00)	($6.00)	$1.40	($3.87)	($3.61)	$0.32	($4.84)	($4.49)
PJM/MISO Interface	($0.62)	($12.51)	($4.55)	($0.03)	($5.75)	($3.16)	($0.48)	($6.28)	($3.85)
LMP: Locational Marginal Price, MCC: Marginal Congestion Component, MLC: Marginal Loss Component									

PJM and NYISO Interface Prices

Figure 4-9 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): January through June 2010 (See 2009 SOM, Figure 4-9)

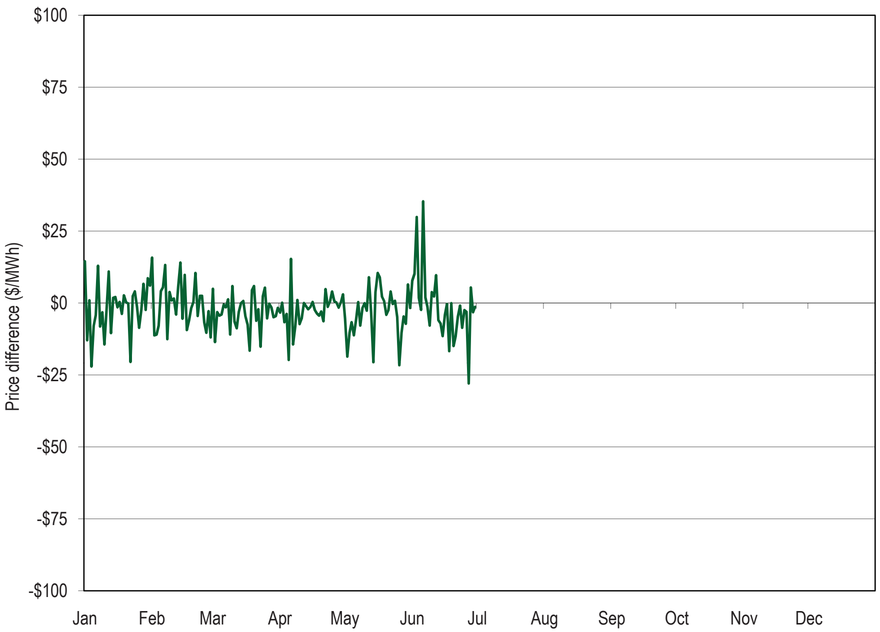


Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through June 2010 (See 2009 SOM, Figure 4-10)

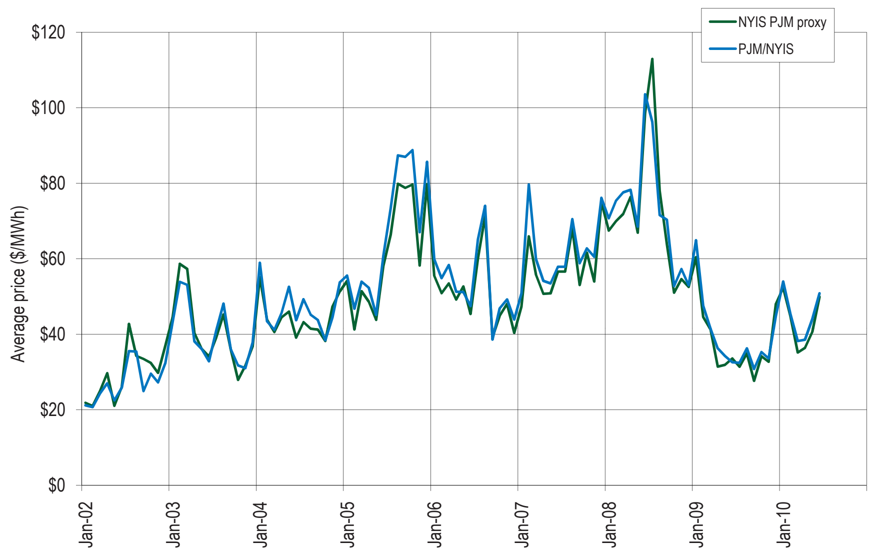


Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through June 2010 (See 2009 SOM, Table 4-11)

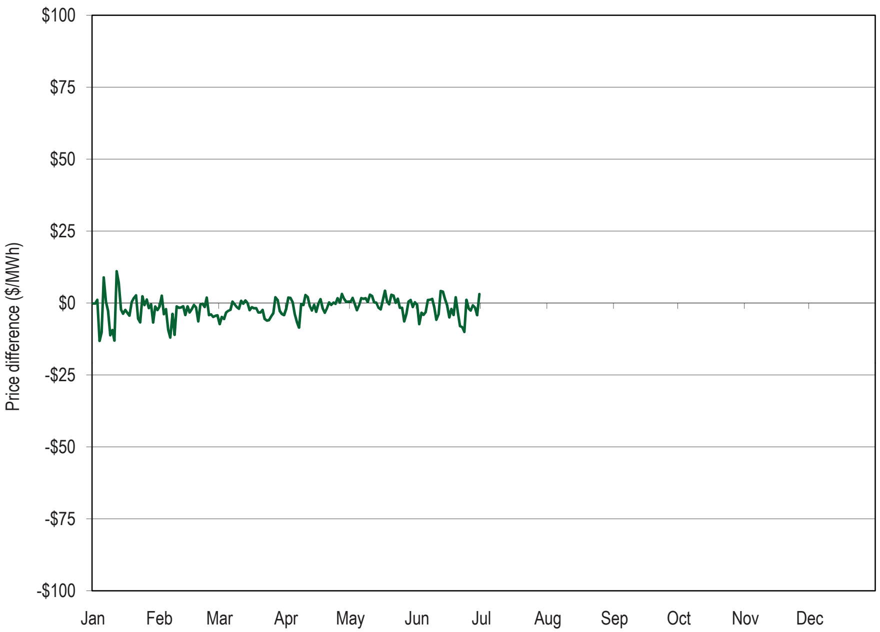
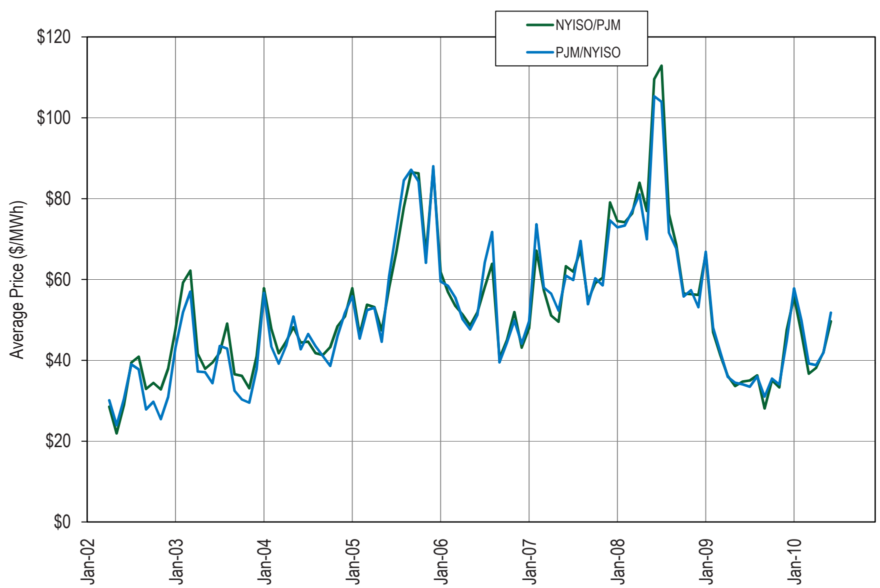


Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through June 2010 (See 2009 SOM, Figure 4-12)



Summary of Interface Prices between PJM and Organized Markets

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: January through June 2010 (See 2009 SOM, Figure 4-13)

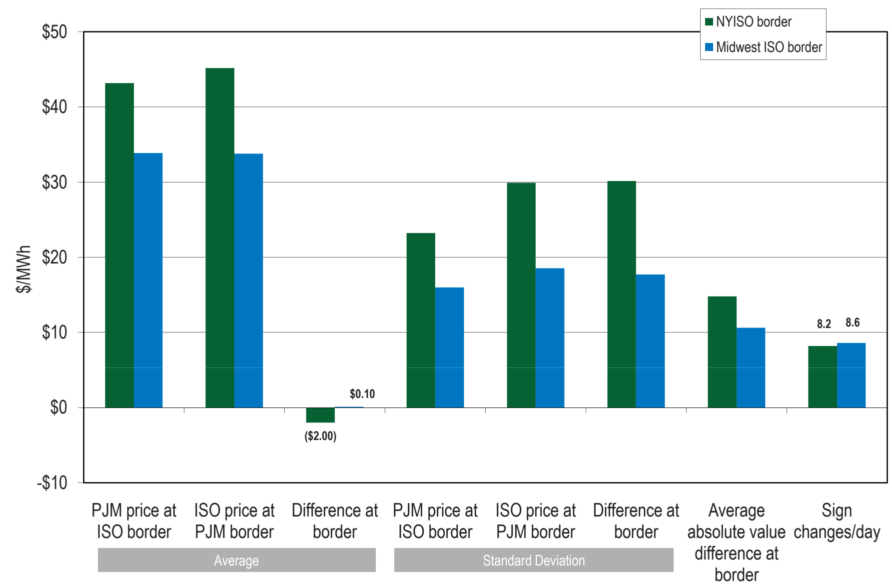
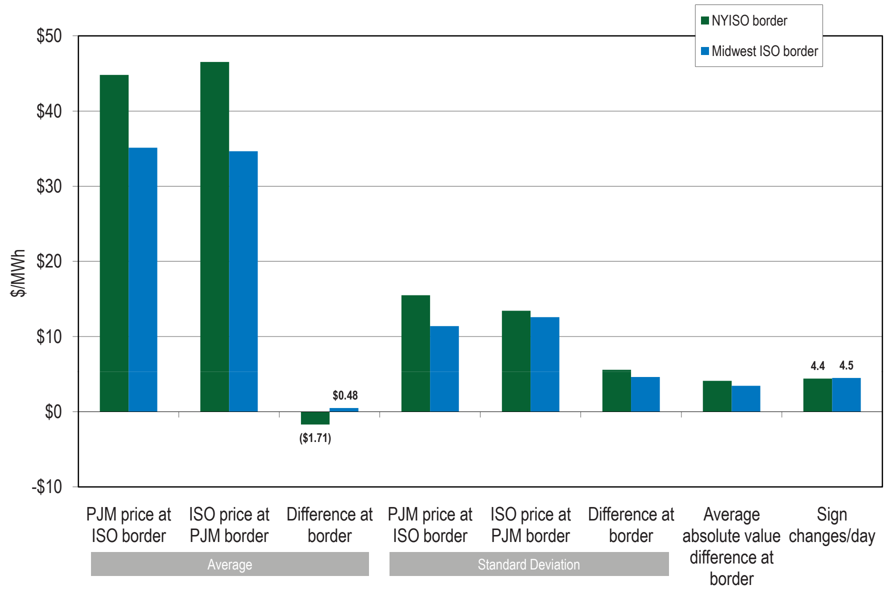


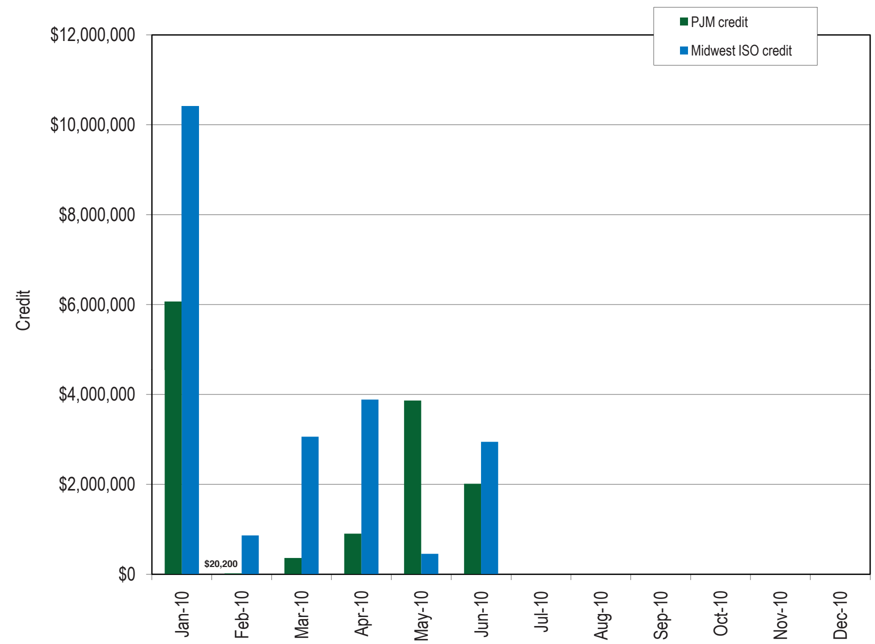
Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: January through June 2010 (See 2009 SOM, Figure 4-14)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement

Figure 4-15 Credits for coordinated congestion management: January through June 2010 (See 2009 SOM, Figure 4-15)



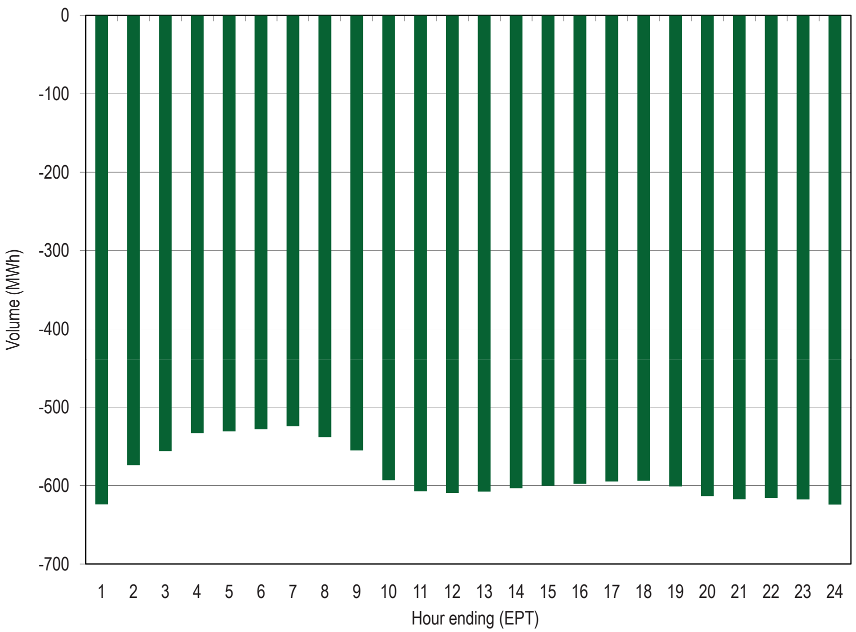
Con Edison and PSE&G Wheeling Contracts

Table 4-11 Con Edison and PSE&G wheeling settlement data: January through June 2010 (See 2009 SOM, Table 4-11)

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total	Congestion Charge	$2,804,473	($21,098)	$2,783,375	$4,654,564	$0	$4,654,564
	Congestion Credit			$1,569,131			$4,147,369
	Adjustments			$11,586			$352,559
	Net Charge			$1,202,658			$154,636

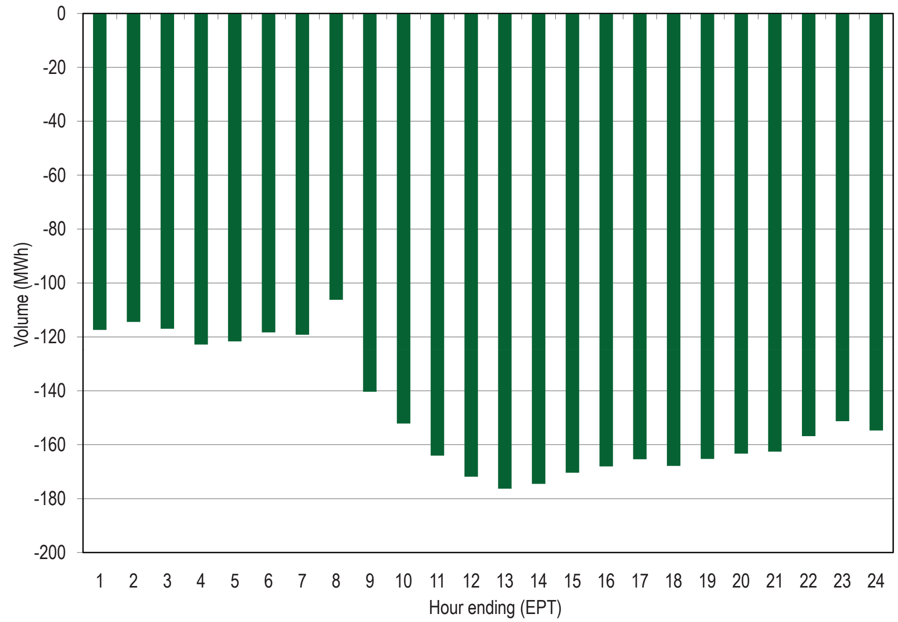
Neptune Underwater Transmission Line to Long Island, NY

Figure 4-16 Neptune hourly average flow: January through June 2010 (See 2009 SOM, Figure 4-16)



Linden Variable Frequency Transformer (VFT) facility

Figure 4-17 Linden hourly average flow: January through June 2010 (See 2009 SOM, Figure 4-17)



Interchange Transaction Issues

Loop Flows

Table 4-12 Net scheduled and actual PJM interface flows (GWh): January through June 2010 (See 2009 SOM, Table 4-12)

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	4,207	(41)	4,248	(10361%)
CPLW	(891)	-	(891)	0%
DUK	(1,350)	265	(1,615)	(609%)
EKPC	175	(126)	301	(239%)
LGEE	624	500	124	25%
MEC	(1,287)	(2,594)	1,307	(50%)
MISO	(3,798)	1,449	(5,247)	(362%)
ALTE	(2,838)	(66)	(2,772)	4200%
ALTW	(991)	(231)	(760)	329%
AMIL	3,148	(303)	3,451	(1139%)
CIN	1,259	2,096	(837)	(40%)
CWLP	(65)	-	(65)	0%
FE	(824)	(1,207)	383	(32%)
IPL	1,561	92	1,469	1597%
MECS	(6,362)	1,305	(7,667)	(588%)
NIPS	(1,152)	(153)	(999)	653%
WEC	2,466	(84)	2,550	(3036%)
NYISO	(5,233)	(7,083)	1,850	(26%)
LIND	(641)	(641)	-	0%
NEPT	(2,545)	(2,545)	-	0%
NYIS	(2,047)	(3,897)	1,850	(47%)
OVEC	3,978	5,834	(1,856)	(32%)
TVA	1,443	(511)	1,954	(382%)
Total	(2,132)	(2,307)	175	(7.6%)

Loop Flows at PJM's Southern Interfaces

Figure 4-18 Southwest actual and scheduled flows: January 2006 through June 2010 (See 2009 SOM, Figure 4-18)

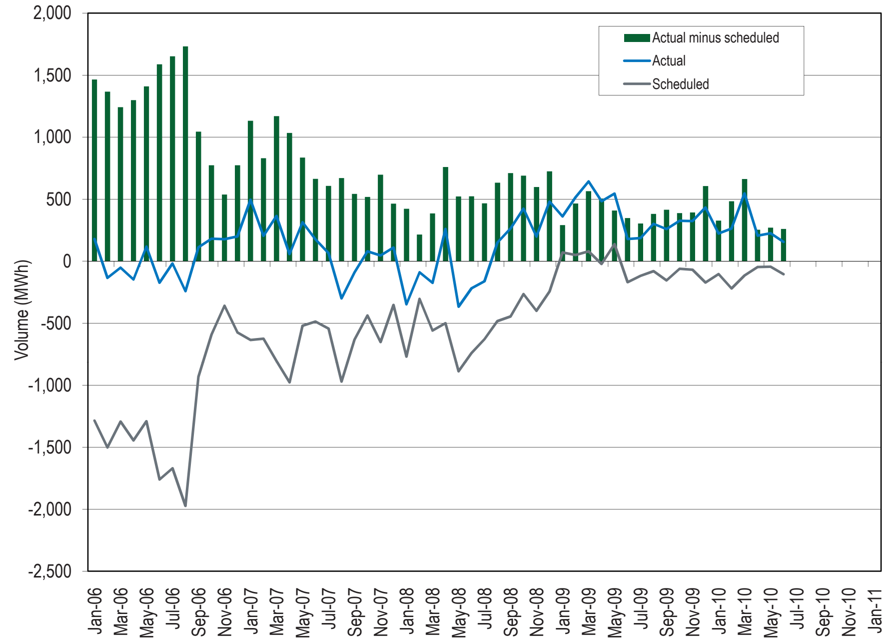
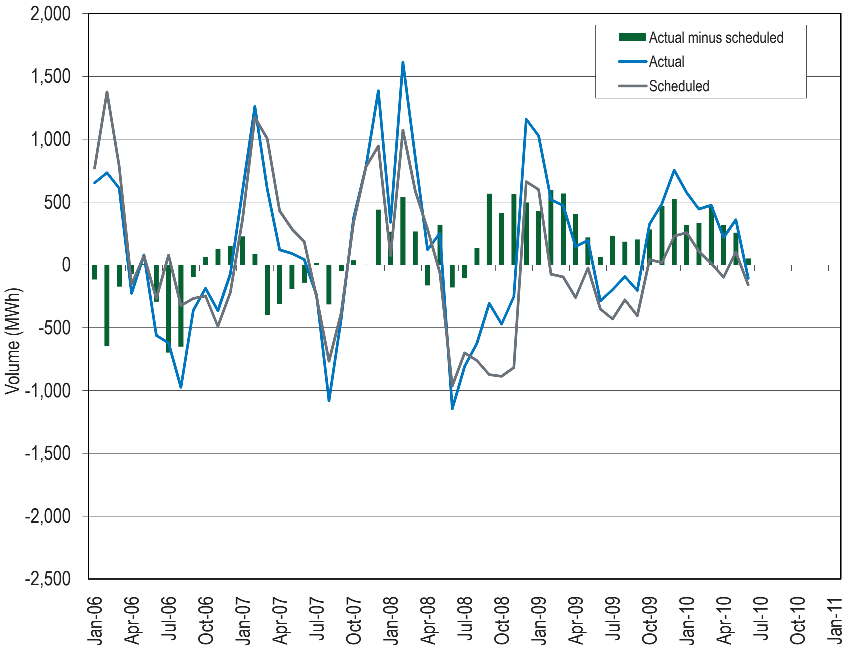


Figure 4-19 Southeast actual and scheduled flows: January 2006 through June 2010 (See 2009 SOM, Figure 4-19)



TLRs

Figure 4-20 PJM and Midwest ISO TLR procedures: Calendar year 2009 and January through June 2010 (See 2009 SOM, Figure 4-20)

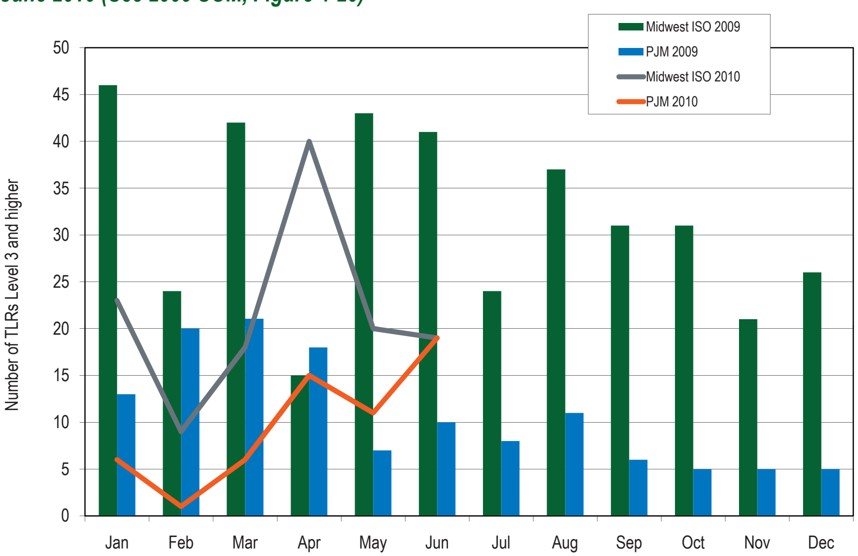


Figure 4-21 Number of different PJM flowgates that experienced TLRs: Calendar year 2009 and January through June 2010 (See 2009 SOM, Figure 4-21)

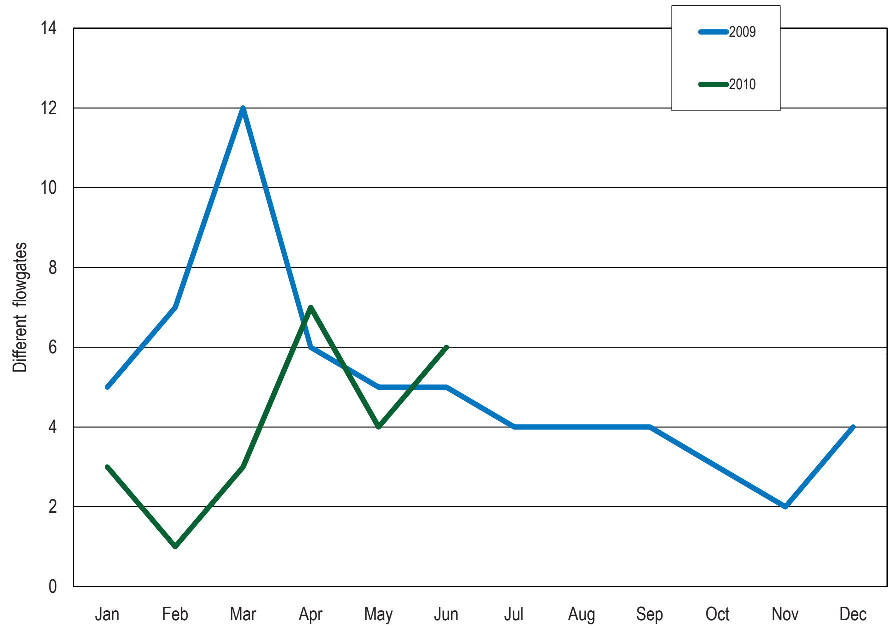


Figure 4-22 Number of PJM TLRs and curtailed volume: January through June 2010 (See 2009, Figure 4-22)

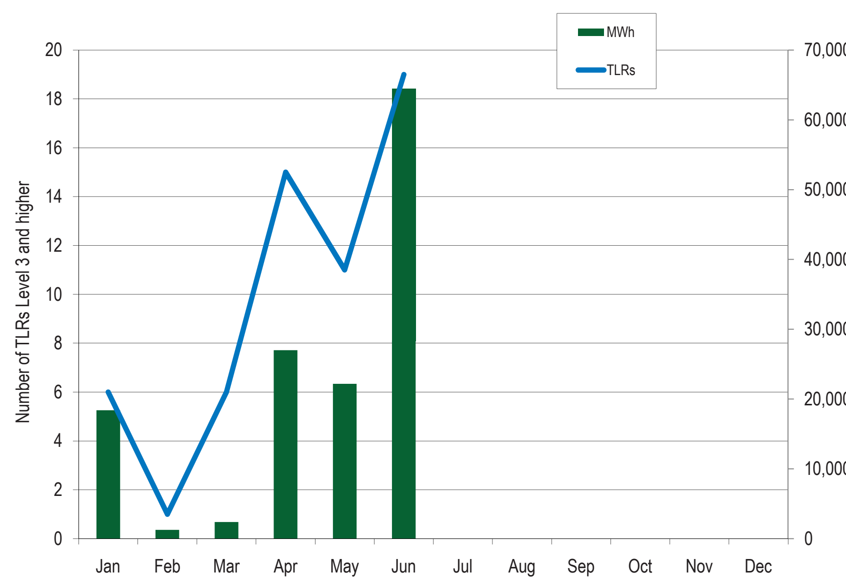


Table 4-13 Number of TLRs by TLR level by reliability coordinator: January through June 2010 (See 2009 SOM, Table 4-13)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2010	ICTE	39	14	65	11	13	0	142
	MISO	73	38	0	10	8	0	129
	NYIS	94	0	0	0	0	0	94
	ONT	44	1	0	0	0	0	45
	PJM	33	25	0	0	0	0	58
	SWPP	96	686	15	25	22	0	844
	TVA	10	13	4	0	1	0	28
Total		389	777	84	46	44	0	1,340

Up-To Congestion

Figure 4-23 Monthly up-to congestion bids in MWh: January 2006 through June 2010 (See 2009 SOM, Figure 4-23)

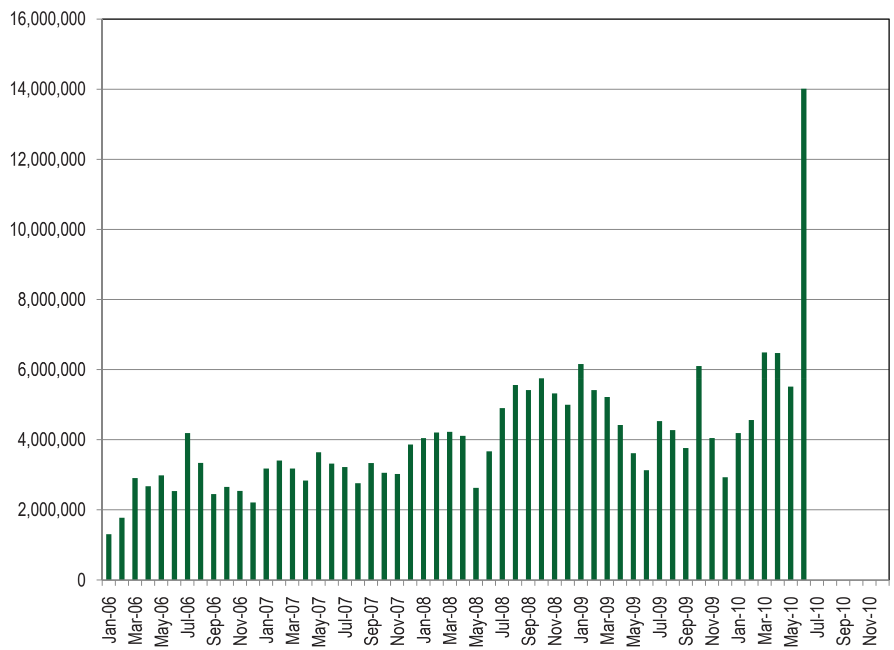


Table 4-14 Up-to congestion MW by Import, Export and Wheels: January 2006 through June 2010 (See 2009 SOM, Table 4-14)

	Import MW	Export MW	Wheeling MW	Total MW	Percent Imports	Percent Exports	Percent Wheels
2006	10,730,659	20,398,833	468,648	31,598,141	34.0%	64.6%	1.5%
2007	13,950,514	24,080,803	817,237	38,848,554	35.9%	62.0%	2.1%
2008	20,889,972	32,351,960	1,632,874	54,874,806	38.1%	59.0%	3.0%
2009	24,455,358	27,722,740	1,453,553	53,631,651	45.6%	51.7%	2.7%
2010	19,506,981	20,436,847	1,323,637	41,267,465	47.3%	49.5%	3.2%
TOTAL	89,533,485	124,991,183	5,695,948	220,220,616	40.7%	56.8%	2.6%

Figure 4-24 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Market transaction: January through June 2010 (See 2009 SOM, Figure 4-24)

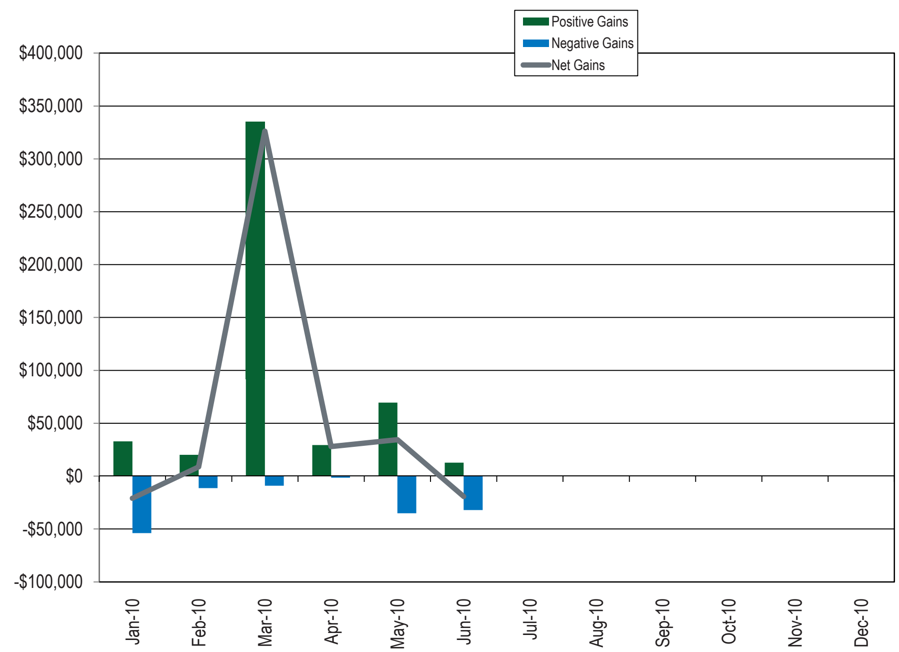
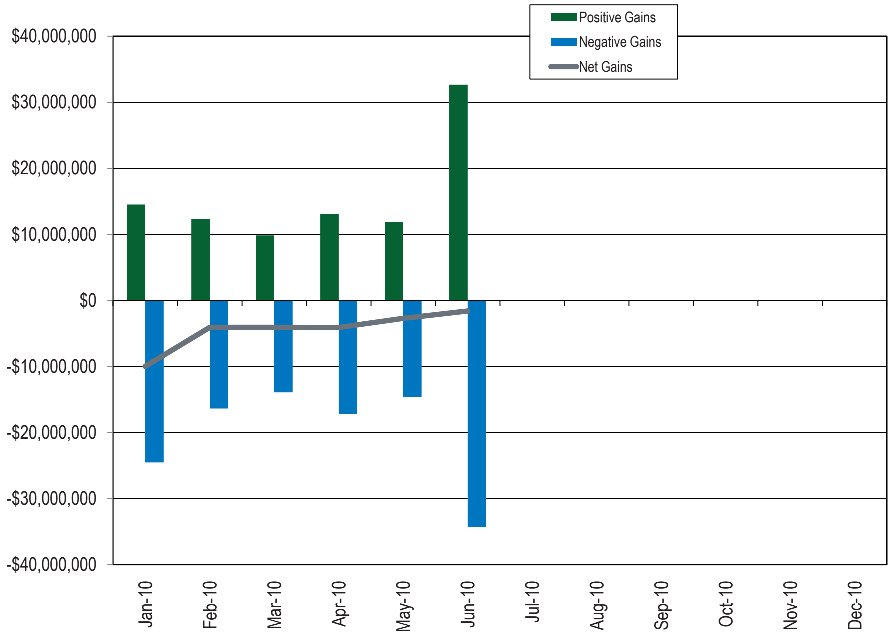


Figure 4-25 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Market transaction: January through June 2010 (See 2009 SOM, Figure 4-25)



Interface Pricing Agreements with Individual Companies

Table 4-15 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through June 2010 (See 2009 SOM, Table 4-15)

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2006	$42.55	$37.89	$38.36	$42.02	$4.20	($0.47)	$0.53	($4.13)
2007	$54.35	$45.48	$49.09	$48.48	$5.26	($3.61)	$5.87	($3.01)
2008	$62.97	$51.43	$55.47	$55.44	$7.50	($4.05)	$7.53	($4.01)
2009	$35.97	$31.94	$33.37	$33.37	$2.61	($1.42)	$2.61	($1.42)
2010	$43.25	$36.01	$38.98	$38.99	$4.27	($2.97)	$4.26	($2.97)

Table 4-16 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through June 2010 (See 2009 SOM, Table 4-17)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.35	$42.18	$38.98	$38.99	$2.36	$3.19
PEC	$42.06	$44.63	$38.98	$38.99	$3.08	$5.64
NCMPA	$41.72	$41.86	$38.98	$38.99	$2.74	$2.87

Figure 4-26 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2010 (See 2009 SOM, Figure 4-26)

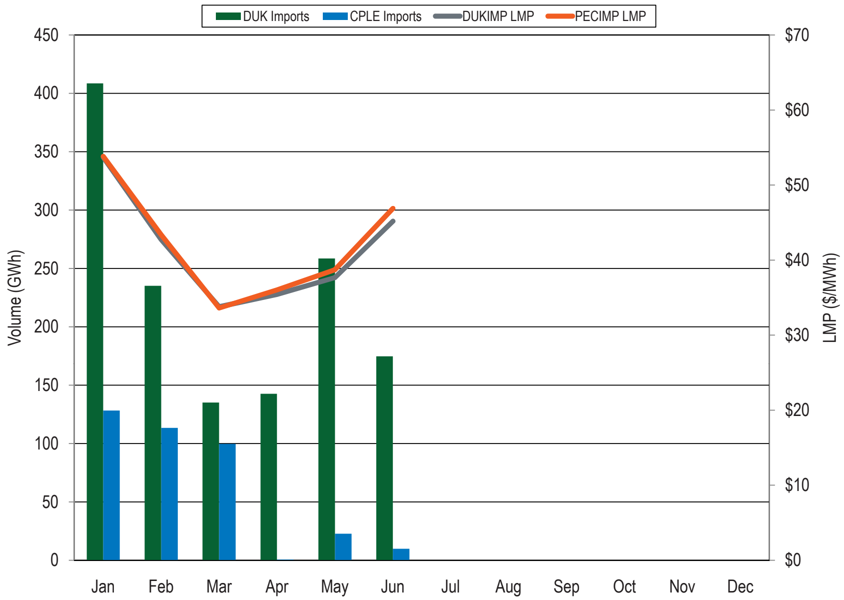


Figure 4-27 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2010 (See 2009 SOM, Figure 4-27)

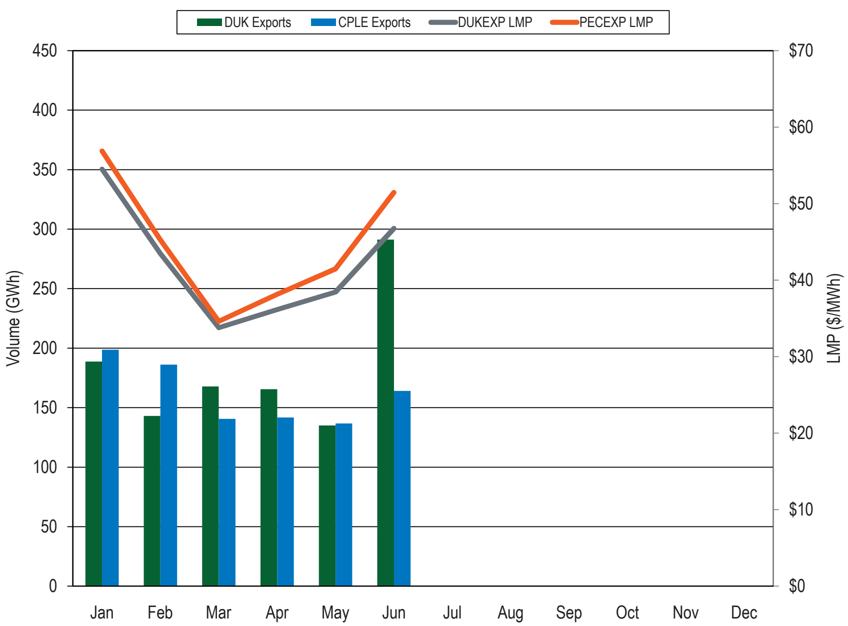


Table 4-17 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through June 2010 (See 2009 SOM, Table 4-19)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$42.01	$43.38	$39.40	$39.40	$2.61	$3.98
PEC	$43.10	$45.86	$39.40	$39.40	$3.70	$6.46
NCMPA	$42.75	$42.90	$39.40	$39.40	$3.35	$3.50

Figure 4-28 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2010 (See 2009 SOM, Figure 4-28)

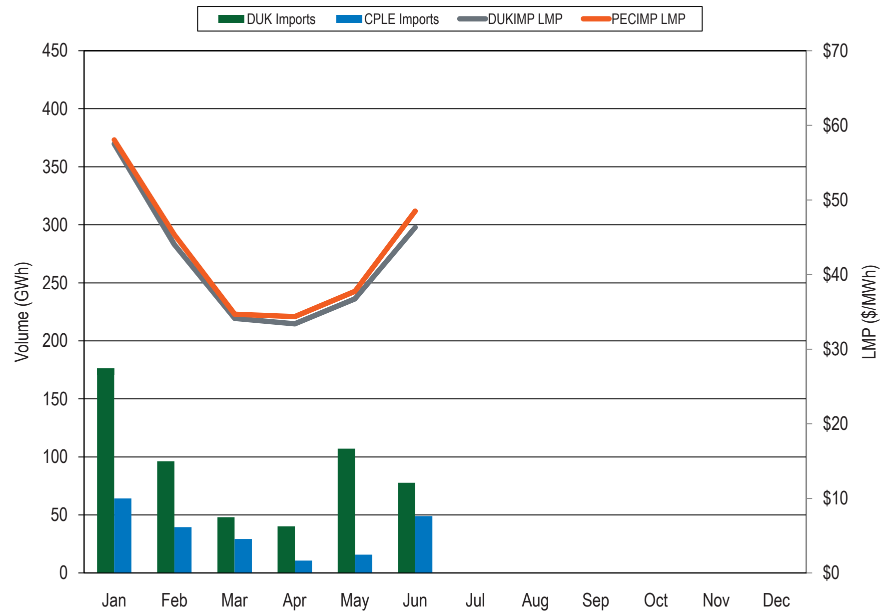
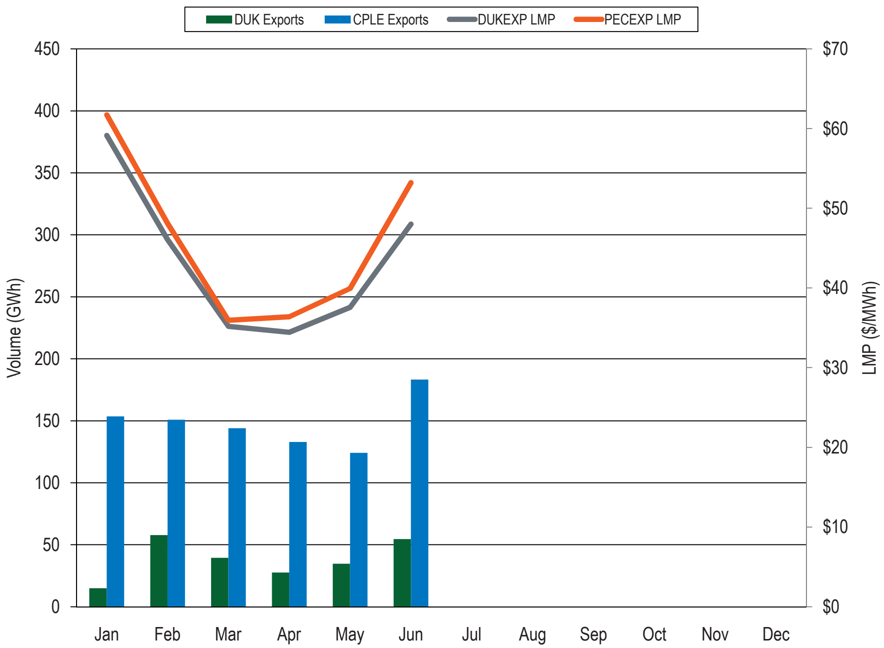
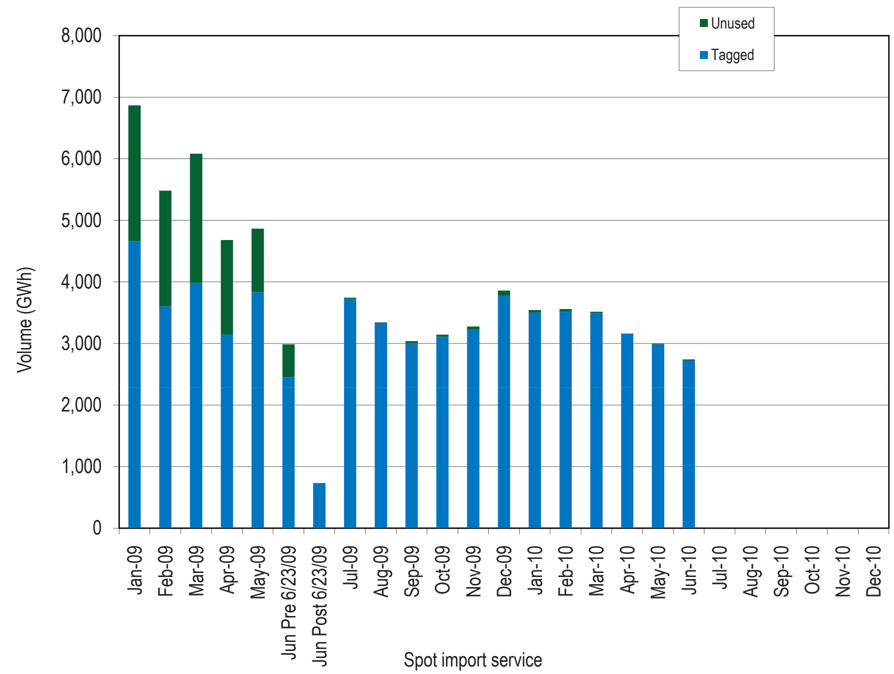


Figure 4-29 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2010 (See 2009 SOM, Figure 4-29)



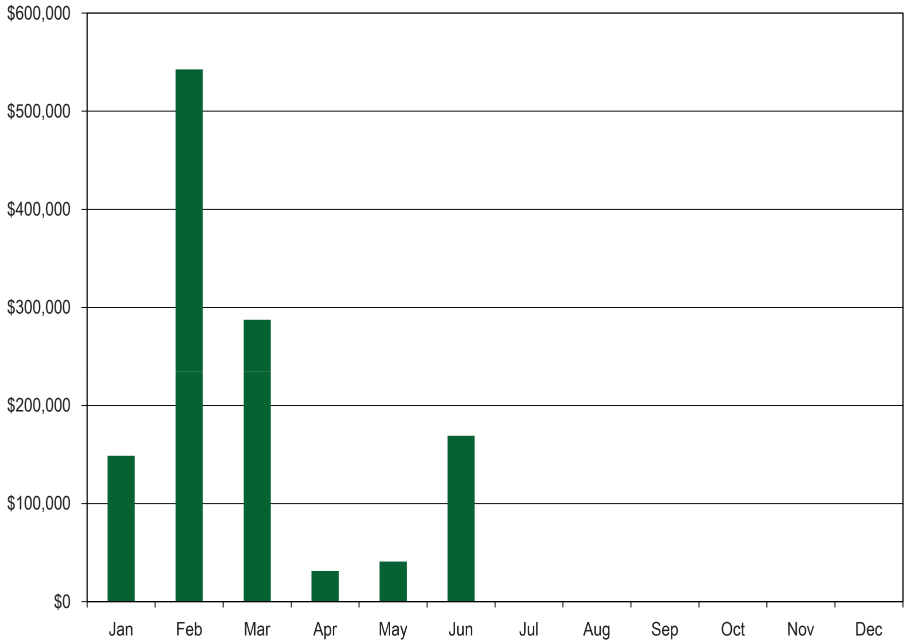
Spot Import

Figure 4-30 Spot import service utilization: January 2009 through June 2010 (See 2009 SOM, Figure 4-30)



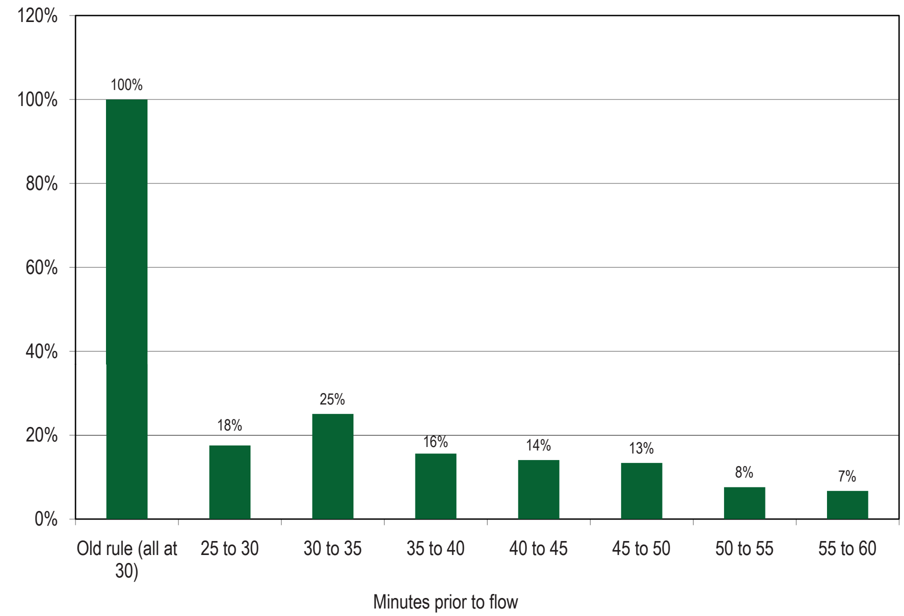
Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-31 Monthly uncollected congestion charges: January through June 2010 (See 2009 SOM, Figure 4-31)



Ramp Availability

Figure 4-32 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through June 2010 (See 2009 SOM, Figure 4-32)



SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity 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.

Overview

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 2010, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region, replacing the Capacity Credit Market (CCM) design that had been in place since 1999.[1] The RPM design represents a significant change in the structure of the Capacity Market in PJM. The RPM 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.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRAs) 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 than 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.** Total internal capacity increased 1,712.7 MW from 157,318.2 MW on June 1, 2009, to 159,030.9 MW on June 1, 2010.[6] This increase was the result of 406.9 MW of new generation, 165.0 MW that came out of retirement, 1,085.8 MW of generation uprates, 43.7 MW of demand

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2010 Quarterly State of the Market Report for PJM: January through June*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
2 126 FERC ¶ 61,275 (2009).
3 *PJM Interconnection, L.L.C.*, OATT Revisions, Docket No. ER10-366-000 (December 1, 2009).
4 See 126 FERC ¶ 61,275 (March 26, 2009), p. 34.
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.
6 Unless otherwise specified, all volumes are in terms of UCAP.

resource (DR) modifications (mods), and a increase of 11.3 MW due to lower Equivalent Demand Forced Outage Rates (EFORds).

In the 2010/2011, 2011/2012, and 2012/2013 auctions, new generation increased 3,969.4 MW; 486.9 MW came out of retirement and net generation deratings were 5,050.1 MW, for a total of -593.8 MW. DR and EE capacity modifications totaled 11,360.5 MW through June 1, 2013. A decrease of 1,481.8 MW was due to higher EFORds. The reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity, and the integration of the ATSI zone resources added 13,175.2 MW. The net effect from June 1, 2010, to June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW.

In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The increase consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new resources consisted of seven CT resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW).

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The increase consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

In the 2012/2013 auction, eight more generating resources made offers than in the 2011/2012 RPM auction. The net increase of eight resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[7] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two CT resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new units consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

In the 2013/2014 auction, 37 more generation resources made offers than in the 2012/2013 auction. The increase in generating resources consisted of 63 ATSI resources that were not offered in the 2012/2013 BRA (11,325.4 MW), 31 new resources (1,038.2 MW), four resources that were previously entirely Fixed Resource Requirement (FRR) committed (234.3 MW), and four additional resources imported (460.1 MW). The reduction in generating resources consisted of seven retired resources (824.0 MW), two deactivated resources (66.6 MW), 49 additional resources committed fully to FRR (307.7 MW), four less planned generation resources that were not offered (249.3 MW), two additional resources excused from offering (4.2 MW), and one less external resource that was not offered (45.7 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2012/2013 BRA: three steam units (125.9 MW). The new generation capacity resources consisted of 11 solar resources (9.5 MW), 11 wind resources (245.7 MW), four combined cycle units (671.5 MW), three diesel resources (5.4 MW), one steam unit (23.8 MW), and one CT unit (82.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2013/2014 delivery year: four wind resources (66.2 MW).

- **Demand.** There was a 3,156.7 MW increase in the RPM reliability requirement from 153,480.1 MW on June 1, 2009 to 156,636.8 MW on June 1, 2010. On June 1, 2010, PJM Electric Distribution Companies (EDCs) and their affiliates maintained a 77.7 percent market share of load obligations under RPM, down from 79.6 percent on June 1, 2009.

7 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

- **Market Concentration.** For the 2010/2011, 2011/2012, 2012/2013, and 2013/2014 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2010/2011 BRA, 2010/2011 Third IA, 2011/2012 BRA, 2011/2012 First IA, and 2013/2014 BRA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test. Six participants included in the incremental supply of EMAAC passed the test. Offer caps were applied to all sell offers that did not pass the test.

- **Imports and Exports.** Net exchange decreased 707.2 MW from June 1, 2009 to June 1, 2010. Net exchange, which is imports less exports, decreased due to an increase in exports of 952.5 MW offset by an increase in imports of 245.3 MW.

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 1,824.9 MW from 7,374.4 MW on June 1, 2009 to 9,199.3 MW on June 1, 2010. Prior to the 2012/2013 delivery year, demand-side resources included DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR). For delivery years 2012/2013 and beyond, ILR was eliminated and demand-side resources include DR and EE resources.

- **Net Excess.** Net excess decreased 537.5 MW from 8,265.5 MW on June 1, 2009 to 7,728.0 MW on June 1, 2010.

Market Conduct

- **2010/2011 RPM Base Residual Auction.** Of the 1,104 generating resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2010/2011 Third Incremental Auction.** Of the 303 generating resources which submitted offers, 193 resources chose the offer cap option of 1.1 times the BRA clearing price (63.7 percent). Unit-specific offer caps were calculated for one resource (0.3 percent). Offer caps of all kinds were calculated for nine resources (2.9 percent), of which seven were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 470 resources (41.8 percent), of which 301 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2011/2012 RPM First Incremental Auction.** Of the 129 generating resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.7 percent). Offer caps of all kinds were calculated for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2012/2013 RPM Base Residual Auction.**[8] Of the 1,133 generating resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). Offer caps of all kinds were calculated for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2013/2014 RPM Base Residual Auction.**[9] Of the 1,170 generating resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). Offer caps of all kinds were calculated for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR calculated by the MMU.

Market Performance

2010/2011 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 159,030.9 MW includes all generation resources and DR that qualified as a PJM capacity resource for the 2010/2011 RPM Base Residual Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. After accounting for FRR committed resources and imports, RPM capacity was 137,360.7 MW. The 132,190.4 MW of cleared resources for the entire RTO represented a reserve margin of 16.5 percent, resulted in net excess of 7,728.0 MW over the reliability

8 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, 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>.

9 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, see "Analysis of the 2013/2014 RPM Base Residual Auction" (July 14, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20100714.pdf>.

requirement of 132,698.8 MW (Installed Reserve Margin (IRM) of 15.5 percent), and resulted in a clearing price of $174.29 per MW-day.

Total cleared resources in the RTO were 132,190.4 MW which resulted in a net excess of 7,728.0 MW, a decrease of 537.5 MW from the net excess of 8,265.5 MW in the 2009/2010 RPM BRA. Certified interruptible load for reliability (ILR) was 8,236.4 MW.

Cleared resources across the entire RTO will receive a total of $8.4 billion based on the unforced MW cleared and the prices in the 2010/2011 RPM BRA, an increase of approximately $9.6 million from the 2009/2010 BRA.

- **DPL South.** Total internal DPL South unforced capacity of 1,546.1 MW includes all generation resources and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. All imports offered into the auction are modeled in the RTO, so total DPL South RPM unforced capacity was 1,546.1 MW.[10] All of the 1,519.7 MW cleared in DPL South were cleared in the RTO before DPL South became constrained. Of the 26.4 MW of incremental supply, none cleared, because all 26.4 MW were priced above the demand curve. The DPL South resource clearing price of $186.12 per MW-day was determined by the intersection of the demand curve and a vertical section of the supply curve.

  Total resources in DPL South were 2,966.7 MW, which when combined with certified ILR of 97.2 MW resulted in a net excess of 14.5 MW (0.5 percent) greater than the reliability requirement of 3,049.4 MW.

2010/2011 RPM Third Incremental Auction

- **RTO.** There were 4,553.9 MW offered into the 2010/2011 Third Incremental Auction while buy bids totaled 5,221.0 MW. Cleared volumes in the RTO were 1,845.8 MW, resulting in an RTO clearing price of $50.00 per MW-day. The 2,708.1 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared resources across the entire RTO will receive a total of $33.7 million based on the unforced MW cleared and the prices in the 2010/2011 RPM Third Incremental Auction.

10 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 10 (Effective June 1, 2010), p. 24, <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.32 MB).

- **DPL South.** Although DPL South was a constrained LDA in the 2010/2011 BRA, supply and demand curves resulted in a price less than the RTO clearing price. Supply offers in the incremental auction in DPL South (56.8 MW) exceeded DPL South demand bids (25.9 MW). The result was that all of DPL South supply which cleared received the RTO clearing price.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 8.1 percent in the first six months of 2009 to 7.8 percent in the first six months of 2010. PJM EFORp decreased from 4.6 percent in the first six months of 2009 to 4.4 percent in the first six months of 2010.[11]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 84.4 percent in the first six months of 2009 to 84.2 percent in the first six months of 2010.

- **Outages Deemed Outside Management Control (OMC).** According to 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. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Conclusion

The 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.

11 2009 data is for the 6 months ended June 30, 2009, as downloaded from the PJM GADS database on July 22, 2010. 2010 data is for the period ending June 30, 2010, as downloaded from the PJM GADS database on July 22, 2010. Annual EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

The 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 during the first six months of 2010. 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 during the first six months of 2010.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[12,13,14,15,16]

12 See "Analysis of the 2010/2011 RPM Auction Revised" (July 3, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20102011-rpm-review-final-revised.pdf>.

13 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>.

14 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>.

15 See "Analysis of the 2013/2014 RPM Base Residual Auction" (July 14, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20100714.pdf>.

16 See *2009 State of the Market Report for PJM*, Section 5, "Capacity Market" (March 11, 2010).

RPM Capacity Market

Market Structure

Supply

Table 5-1 Internal capacity: June 1, 2009, to June 1, 2013[17] (See 2009 SOM, Table 5-1)

	UCAP (MW)					
	RTO	MAAC	EMAAC	DPL South	PSEG North	Pepco
Total internal capacity @ 01-Jun-09	157,318.2			1,587.0		
New generation	406.9			0.0		
Units out of retirement	165.0			0.0		
Generation capmods	1,085.8			(85.5)		
DR mods	43.7			15.7		
Net EFORd effect	11.3			28.9		
Total internal capacity @ 01-Jun-10	159,030.9			1,546.1		
New generation	2,203.7					
Units out of retirement	486.9					
Generation capmods	(2,567.6)					
DR mods	684.4					
Net EFORd effect	44.4					
Total internal capacity @ 01-Jun-11	159,882.7	66,329.7	32,733.0	1,460.3	4,167.5	
Reclassification of Duquesne resources	3,187.2	0.0	0.0	0.0	0.0	
Adjusted internal capacity @ 01-Jun-11	163,069.9	66,329.7	32,733.0	1,460.3	4,167.5	
New generation	661.3	61.9	59.7	0.0	0.0	
Units out of retirement	0.0	0.0	0.0	0.0	0.0	
Generation capmods	(1,513.1)	(901.3)	(444.9)	(31.8)	(509.0)	
DR mods	8,028.7	3,829.7	1,480.9	64.6	67.6	
EE mods	652.5	186.9	24.4	0.0	0.9	
Net EFORd effect	(946.0)	(503.0)	(185.6)	5.8	18.3	
Total internal capacity @ 01-Jun-12	169,953.3	69,003.9	33,667.5	1,498.9	3,745.3	5,416.0
Correction in resource modeling	0.0	13.0	0.0			0.0
Adjusted internal capacity @ 01-Jun-12	169,953.3	69,016.9	33,667.5			5,416.0
Integration of existing ATSI resources	13,175.2	0.0	0.0			0.0
New generation	1,104.4	172.5	110.3			1.8
Units out of retirement	0.0	0.0	0.0			0.0
Generation capmods	(969.4)	(1,007.7)	(884.9)			(11.0)
DR mods	1,894.1	900.2	689.5			61.8
EE mods	100.8	(34.9)	(0.3)			(20.7)
Net EFORd effect	(580.2)	31.9	118.5			(159.0)
Total internal capacity @ 01-Jun-13	184,678.2	69,078.9	33,700.6			5,288.9

17 The RTO includes MAAC, EMAAC and SWMAAC. MAAC includes EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. SWMAAC includes Pepco. Results for only constrained LDAs are shown. Maps of the LDAs can be found in the *2009 State of the Market Report for PJM*, Appendix A, "PJM Geography."

Demand

Table 5-2 PJM Capacity Market load obligation served: June 1, 2010 (See 2009 SOM, Table 5-2)

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	66,223.4	12,774.7	24,974.3	1,144.4	12,755.6	567.1	15,408.6	133,848.1
Percent of total obligation	49.5%	9.5%	18.7%	0.9%	9.5%	0.4%	11.5%	100.0%

Market Concentration

Preliminary Market Structure Screen

Table 5-3 Preliminary market structure screen results: 2009/2010 through 2013/2014 RPM Auctions (See 2009 SOM, Table 5-3)

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2010/2011				
RTO	18.4%	853	1	Fail
EMAAC	31.3%	2053	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	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

Auction Market Structure

Table 5-4 RSI results: 2010/2011 through 2013/2014 RPM Auctions[18] (See 2009 SOM, Table 5-4)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2010/2011 BRA			
RTO	0.60	68	68
DPL South	0.00	2	2
2010/2011 Third IA			
RTO	0.53	47	47
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First IA			
RTO	0.62	30	30
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
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

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

Imports and Exports

Table 5-5 PJM capacity summary (MW): June 1, 2007, to June 1, 2013[19] (See 2009 SOM, Table 5-5)

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	3,199.6	5,976.5	6,518.3
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9
EE cleared						568.9	679.4
ILR	1,636.3	3,608.1	6,481.5	8,236.4	1,593.8		
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6
Short-Term Resource Procurement Target						3,343.3	3,749.7

19 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

Demand-Side Resources

Table 5-6 RPM load management statistics: June 1, 2009 to June 1, 2013[20,21] (See 2009 SOM, Table 5-6)

	UCAP (MW)							
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
DR cleared	892.9	813.9			356.3			
ILR certified	6,481.5	1,055.7			345.7			
RPM load management @ 01-June-2009	7,374.4	1,869.6			702.0			
DR cleared	962.9					14.9		
ILR certified	8,236.4					97.2		
RPM load management @ 01-June-2010	9,199.3					112.1		
DR cleared	1,364.9							
ILR forecast	1,593.8							
RPM load management @ 01-June-2011	2,958.7							
DR cleared	7,047.2		4,723.7	1,638.4		64.6	67.6	
EE cleared	568.9		179.9	20.0		0.0	0.9	
RPM load management @ 01-June-2012	7,616.1		4,903.6			64.6	68.5	
DR cleared	9,281.9		5,871.1	2,461.3				547.3
EE cleared	679.4		152.0	23.9				35.8
RPM load management @ 01-June-2013	9,961.3		6,023.1	2,485.2				583.1

20 For delivery years through 2010/2011, certified ILR data were used in the calculation, because the certified ILR data are now available. PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012. Effective the 2012/2013 delivery year, ILR was eliminated and the Energy Efficiency (EE) resource type was eligible to be offered in RPM auctions.

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

Market Conduct

Offer Caps

Table 5-7 ACR statistics: 2010/2011 RPM Auctions (See 2009 SOM,)

	2010/2011 BRA		2010/2011 Third IA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	370	33.5%	7	2.3%
ACR data input (APIR)	134	12.1%	1	0.3%
ACR data input (non-APIR)	20	1.8%	0	0.0%
Opportunity cost input	8	0.7%	1	0.3%
Default ACR and opportunity cost input	0	0.0%	0	0.0%
Generation resources with offer caps	532	48.1%	9	2.9%
Uncapped planned generation resources	15	1.4%	0	0.0%
Generators capped at 1.1 times BRA clearing price	NA		193	63.7%
Generation price takers	557	50.5%	101	33.4%
Generation resources offered	1,104	100.0%	303	100.0%
Demand resources offered	23		34	
Energy efficiency resources offered	0		0	
Total capacity resources offered	1,127		337	

Table 5-8 ACR statistics: 2011/2012 through 2013/2014 RPM Auctions[22] (See 2009 SOM, Table 5-8)

	2011/2012 BRA		2011/2012 First IA		2012/2013 BRA		2013/2014 BRA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	299	26.6%	44	34.1%	465	41.0%	580	49.6%
ACR data input (APIR)	133	11.8%	18	14.0%	118	10.4%	92	7.9%
ACR data input (non-APIR)	12	1.1%	1	0.8%	2	0.2%	15	1.3%
Opportunity cost input	24	2.1%	2	1.6%	8	0.7%	6	0.5%
Default ACR and opportunity cost input	2	0.2%	3	2.3%	14	1.2%	7	0.6%
Generation resources with offer caps	470	41.8%	68	52.8%	607	53.5%	700	59.9%
Uncapped planned generation resources	20	1.8%	1	0.8%	11	1.0%	20	1.7%
Generators capped at 1.1 times BRA clearing price	NA		NA		NA		NA	
Generation price takers	635	56.4%	60	46.4%	515	45.5%	450	38.4%
Generation resources offered	1,125	100.0%	129	100.0%	1,133	100.0%	1,170	100.0%
Demand resources offered	37		0		233		426	
Energy efficiency resources offered	0		0		53		128	
Total capacity resources offered	1,162		129		1,419		1,724	

22 The ACR statistics have been updated since the MMU RPM Auction reports were posted.

Table 5-9 APIR statistics: 2010/2011 through 2013/2014 RPM Auctions[23,24,25,26] (See 2009 SOM, Table 5-9)

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2010/2011 BRA							
Non-APIR units	ACR	$34.39	$27.10	$67.57	$167.08	$82.55	$80.86
	Net revenues	$96.75	$18.81	$15.19	$302.79	$391.00	$151.31
	Offer caps	$10.13	$14.12	$52.38	$9.67	$4.53	$11.94
APIR units	ACR	$61.61	$49.26	$152.09	$654.18	$34.62	$360.27
	Net revenues	$26.84	$10.32	$20.94	$525.48	$2.07	$263.27
	Offer caps	$37.30	$39.41	$131.15	$155.39	$32.55	$110.25
	APIR	$9.87	$30.93	$60.54	$521.16	$22.42	$272.18
	Maximum APIR effect						$577.03
2011/2012 BRA							
Non-APIR units	ACR	$39.52	$30.17	$72.20	$181.52	$62.54	$75.61
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78	$169.93
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$17.64
APIR units	ACR	$61.66	$56.28	$184.34	$723.65	$36.03	$424.49
	Net revenues	$78.17	$10.35	$19.81	$531.93	$2.06	$286.80
	Offer caps	$34.69	$46.18	$164.54	$203.41	$33.97	$147.77
	APIR	$11.82	$37.28	$91.30	$578.47	$24.68	$324.58
	Maximum APIR effect						$523.26
2011/2012 First IA							
Non-APIR units	ACR	$54.15	$29.43	NA	$284.63	$30.04	$169.77
	Net revenues	$220.31	$44.98	NA	$298.96	$0.07	$195.83
	Offer caps	$2.66	$2.64	NA	$150.63	$29.97	$83.01
APIR units	ACR	$220.20	$152.28	$194.25	$583.59	NA	$326.57
	Net revenues	$81.72	$6.94	$23.64	$328.71	NA	$128.90
	Offer caps	$138.48	$145.34	$170.62	$254.88	NA	$197.67
	APIR	$220.19	$120.84	$82.87	$324.31	NA	$170.61
	Maximum APIR effect						$468.26

23 The weighted-average offer cap can be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer cap minimum being zero. On a unit basis, if net revenues are greater than ACR, the offer cap is zero.
24 This table has been updated since the MMU RPM Auction reports were posted. The 2010/2011 and 2011/2012 BRA values for Oil and Gas Steam and Sub Critical/Super Critical Coal for resources with an APIR component were updated due to a prior misclassification.
25 For reasons of confidentiality, the APIR statistics do not include opportunity cost based offer cap data.
26 Statistics for the 2010/2011 Third IA are not included as the majority of the resources chose the offer cap option of 1.1 times the BRA clearing price.

Table 5-9 APR statisitics: 2010/2011 through 2013/2014 RPM Auctions (See 2009 SOM, Table 5-9) [continued]

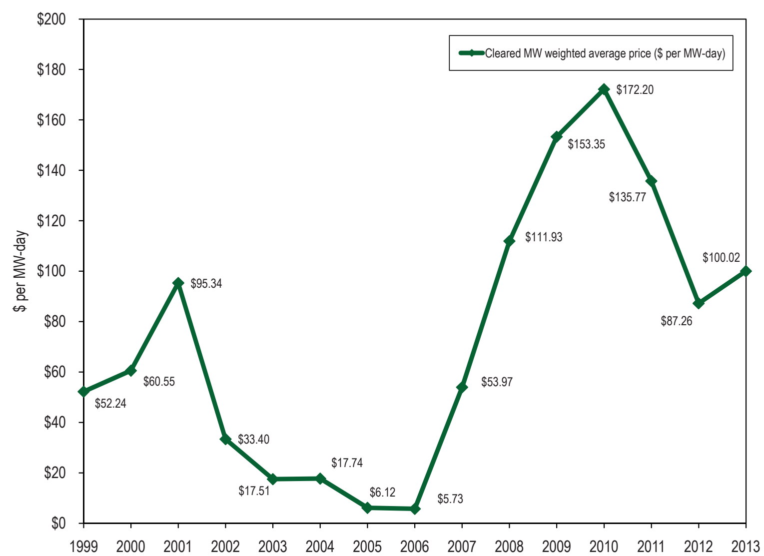
		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2012/2013 BRA							
Non-APIR units	ACR	$41.84	$32.61	$75.47	$207.54	$57.18	$110.84
	Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96	$208.65
	Offer caps	$5.28	$14.40	$67.96	$11.31	$15.63	$13.74
APIR units	ACR	$218.10	$49.83	$177.52	$715.10	NA	$464.65
	Net revenues	$98.97	$15.62	$3.62	$508.00	NA	$302.04
	Offer caps	$119.12	$34.96	$173.89	$215.38	NA	$167.62
	APIR	$218.10	$26.59	$89.08	$559.97	NA	$351.74
	Maximum APIR effect						$1,155.57
2013/2014 BRA							
Non-APIR units	ACR	$44.51	$33.30	$79.91	$212.68	$52.57	$115.83
	Net revenues	$110.63	$30.53	$12.72	$364.90	$259.34	$199.44
	Offer caps	$6.84	$16.36	$68.15	$9.29	$14.30	$14.09
APIR units	ACR	NA	$49.42	$341.77	$509.95	$305.48	$390.05
	Net revenues	NA	$9.18	$63.80	$459.41	$187.40	$292.92
	Offer caps	NA	$40.73	$277.96	$112.30	$118.09	$134.44
	APIR	NA	$25.28	$243.47	$352.55	$1.69	$268.59
	Maximum APIR effect						$1,304.36

Market Performance

Table 5-10 Capacity prices: 2007/2008 through 2013/2014 RPM Auctions (See 2009 SOM, Table 5-10)

	RPM Clearing Price ($ per MW-day)						
	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North
2007/2008 BRA	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67
2008/2009 BRA	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80
2008/2009 Third IA	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00
2009/2010 BRA	$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32
2009/2010 Third IA	$40.00	$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
2010/2011 Third IA	$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
2011/2012 First IA	$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
2012/2013 BRA	$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00
2012/2013 ATSI FRR Integration Auction	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2013/2014 BRA	$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00

Figure 5-1 History of capacity prices: Calendar year 1999 through 2013[27] (See 2009 SOM, Figure 5-1)



27 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2013 capacity prices are RPM weighted average prices.

Table 5-11 RPM cost to load: 2010/2011 through 2013/2014 RPM Auctions[28,29,30] (See 2009 SOM, Table 5-11)

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2010/2011 BRA			
RTO	$182.85	129,332.6	$8,631,690,057
DPL	$187.04	4,515.5	$308,271,379
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034
2012/2013 BRA			
RTO	$16.46	69,648.3	$418,440,022
MAAC	$129.63	31,338.7	$1,482,789,024
EMAAC	$135.18	21,171.5	$1,044,616,630
DPL	$162.99	4,685.6	$278,752,670
PSEG	$149.65	12,642.7	$690,572,720
2013/2014 BRA			
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

28 The annual charges are calculated using the rounded, net load prices as posted by PJM.
29 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.
30 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second IA. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third IA. 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 2011/2012, 2012/2013, and 2013/2014 Net Load Prices and UCAP Obligation MW are not finalized.

2010/2011 RPM Base Residual Auction

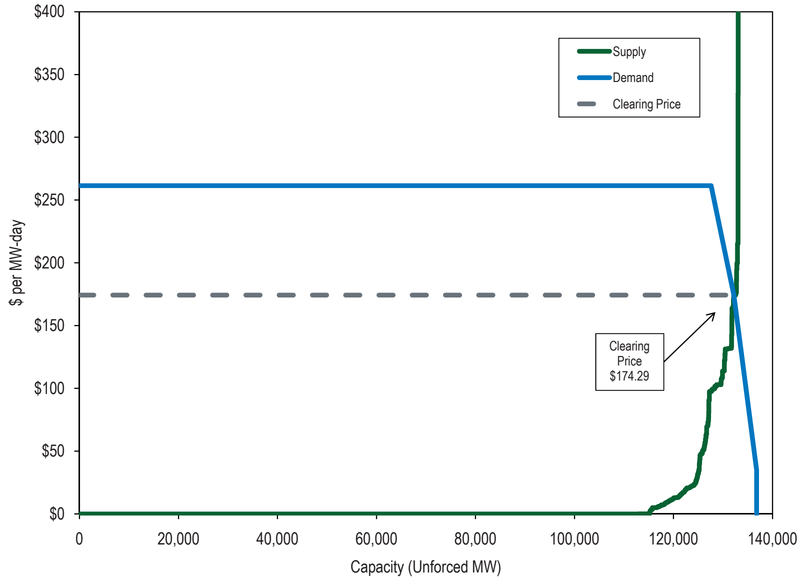
RTO

Table 5-12 RTO offer statistics: 2010/2011 RPM Base Residual Auction[31] (See Analysis of the 2010/2011 RPM Auction Revised)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal RTO capacity (gen and DR)	168,457.3	159,030.9		
FRR	(26,305.7)	(24,420.9)		
Imports	2,982.4	2,750.7		
RPM capacity	145,134.0	137,360.7		
Exports	(3,378.2)	(3,147.4)		
FRR optional	(744.5)	(630.5)		
Excused	(546.2)	(490.1)		
Available	140,465.1	133,092.7	100.0%	100.0%
Generation offered	139,529.5	132,124.8	99.3%	99.3%
DR offered	935.6	967.9	0.7%	0.7%
Total offered	140,465.1	133,092.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	139,253.9	132,190.4	99.1%	99.3%
Cleared in LDAs	0.0	0.0	0.0%	0.0%
Total cleared	139,253.9	132,190.4	99.1%	99.3%
Make-whole	0.0	0.0	0.0%	0.0%
Uncleared in RTO	1,184.5	875.9	0.9%	0.7%
Uncleared in LDAs	26.7	26.4	0.0%	0.0%
Total uncleared	1,211.2	902.3	0.9%	0.7%
Reliability requirement		132,698.8		
Total cleared plus make-whole		132,190.4		
ILR certified		8,236.4		
Net excess/(deficit)		7,728.0		
Resource clearing price ($ per MW-day)		$174.29	A	
Final zonal capacity price ($ per MW-day)		$182.85	B	
Final zonal CTR credit rate ($ per MW-day)		$0.00	C	
Final zonal ILR price ($ per MW-day)		$174.29	A-C	
Net load price ($ per MW-day)		$182.85	B-C	

31 Prices are only for those generating units outside of DPL South.

Figure 5-2 RTO market supply/demand curves: 2010/2011 RPM Base Residual Auction[32] (See Analysis of the 2010/2011 RPM Auction Revised)



32 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in DPL South.

DPL South

Table 5-13 DPL South offer statistics: 2010/2011 RPM Base Residual Auction[33] (See Analysis of the 2010/2011 RPM Auction Revised)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal DPL South capacity (gen and DR)	1,652.3	1,546.1		
Imports	0.0	0.0		
RPM capacity	1,652.3	1,546.1		
Exports	0.0	0.0		
Excused	0.0	0.0		
Available	1,652.3	1,546.1	100.0%	100.0%
Generation offered	1,637.1	1,530.4	99.1%	99.0%
DR offered	15.2	15.7	0.9%	1.0%
Total offered	1,652.3	1,546.1	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	1,625.6	1,519.7	98.4%	98.3%
Cleared in LDA	0.0	0.0	0.0%	0.0%
Total cleared	1,625.6	1,519.7	98.4%	98.3%
Make-whole	0.0	0.0	0.0%	0.0%
Uncleared	26.7	26.4	1.6%	1.7%
Reliability requirement		3,049.4		
Total cleared plus make-whole		1,519.7		
CETL		1,447.0		
Total resources		2,966.7		
ILR certified		97.2		
Net excess/(deficit)		14.5		
Resource clearing price ($ per MW-day)		$186.12		
DPL zone weighted average resource clearing price ($ per MW-day)		$178.57	A	
Final zonal capacity price ($ per MW-day)		$187.34	B	
Final zonal CTR credit rate ($ per MW-day)		$0.30	C	
Final zonal ILR price ($ per MW-day)		$178.27	A-C	
Net load price ($ per MW-day)		$187.04	B-C	

33 There is no separate zonal capacity price or CTR credit rate for DPL South as the DPL South LDA is completely contained within the DPL Zone.

2010/2011 RPM Third Incremental Auction

RTO

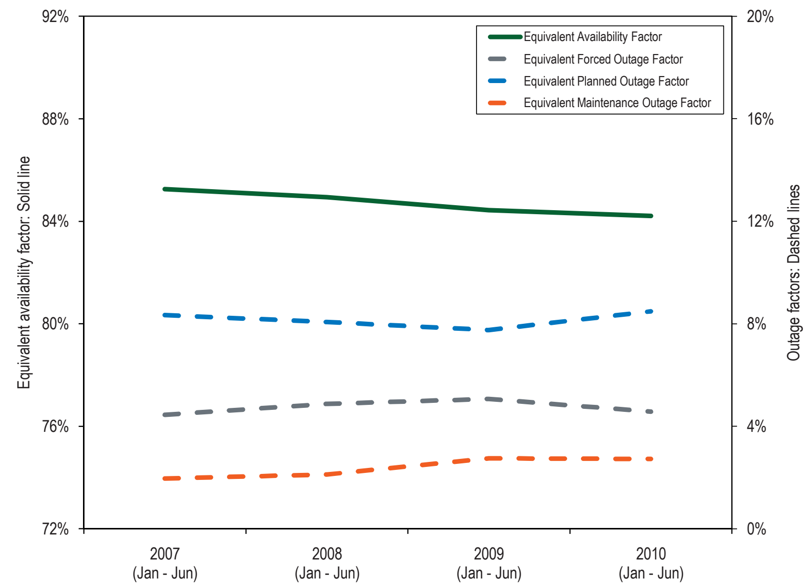
Table 5-14 RTO offer statistics: 2010/2011 RPM Third Incremental Auction (New table)

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	3,274.3	3,102.3	
DR	1,402.9	1,451.6	
Total	4,677.2	4,553.9	5,221.0
Cleared in RTO	1,947.6	1,845.8	1,845.8
Cleared in LDAs	0.0	0.0	0.0
Total cleared	1,947.6	1,845.8	1,845.8
Uncleared in RTO	2,729.6	2,708.1	3,375.2
Uncleared in LDAs	0.0	0.0	0.0
Total uncleared	2,729.6	2,708.1	3,375.2
Resource clearing price ($ per MW-day)		$50.00	

Generator Performance

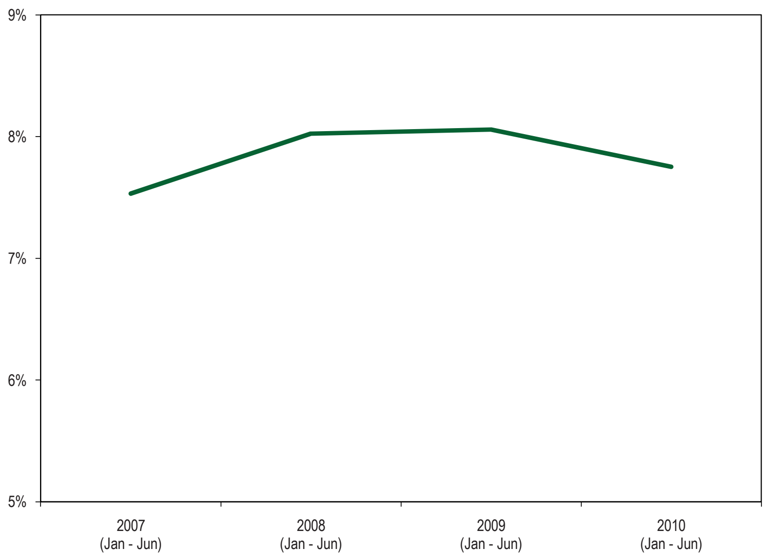
Generator Performance Factors

Figure 5-3 PJM equivalent outage and availability factors: 2007 to 2010 (January through June) (See 2009 SOM, Figure 5-7)



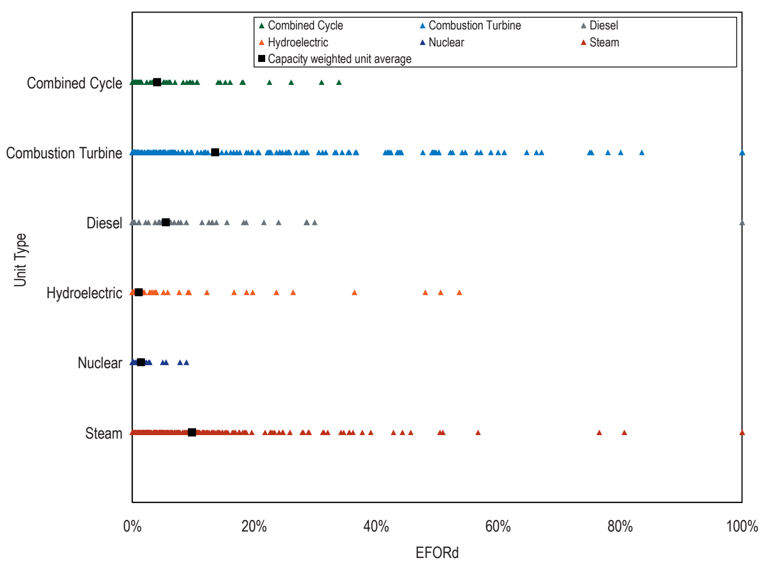
Generator Forced Outage Rates

Figure 5-4 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 to 2010 (January through June) (See 2009 SOM, Figure 5-8)



Distribution of EFORd

Figure 5-5 PJM 2010 (January through June) Distribution of EFORd data by unit type (See 2009 SOM, Figure 5-9)



Components of EFORd

Table 5-15 PJM EFORd data for different unit types: 2007 to 2010 (January through June) (See 2009 SOM, Table 5-17)

	2007 (Jan - Jun)	2008 (Jan - Jun)	2009 (Jan - Jun)	2010 (Jan - Jun)
Combined Cycle	3.5%	3.1%	4.6%	4.1%
Combustion Turbine	16.7%	13.9%	10.3%	13.6%
Diesel	10.7%	10.2%	8.5%	5.5%
Hydroelectric	2.2%	2.1%	2.3%	1.1%
Nuclear	1.2%	1.1%	4.0%	1.4%
Steam	8.7%	10.6%	10.3%	9.8%
Total	7.5%	8.0%	8.1%	7.8%

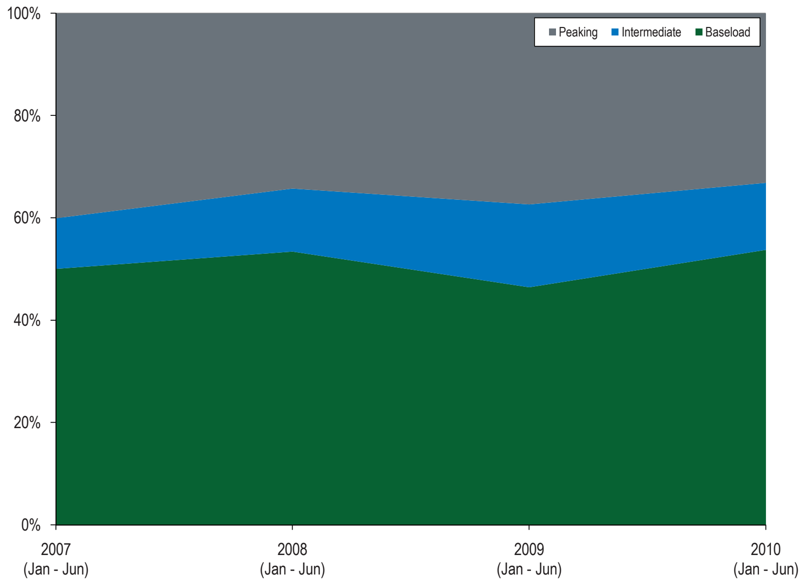
Table 5-16 Contribution to EFORd for specific unit types (Percentage points): 2007 to 2010 (January through June)[34] (See 2009 SOM, Table 5-18)

	2007 (Jan - Jun)	2008 (Jan - Jun)	2009 (Jan - Jun)	2010 (Jan - Jun)
Combined Cycle	0.5	0.4	0.6	0.5
Combustion Turbine	2.5	2.1	1.6	2.1
Diesel	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.0
Nuclear	0.2	0.2	0.7	0.3
Steam	4.2	5.2	5.0	4.8
Total	7.5	8.0	8.1	7.8

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.

Duty Cycle and EFORd

Figure 5-6 Contribution to EFORd by duty cycle: 2007 to 2010 (January through June) (See 2009 SOM, Figure 5-10)



Forced Outage Analysis

Table 5-17 Outage cause contribution to PJM EFOF: Calendar year 2010 (January through June) (See 2009 SOM, Table 5-19)

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	1.11	21.9%
Economic	0.60	11.9%
Boiler Internals and Structures	0.38	7.5%
Electrical	0.34	6.7%
Boiler Air and Gas Systems	0.29	5.7%
Boiler Fuel Supply from Bunkers to Boiler	0.16	3.3%
Feedwater System	0.16	3.1%
Fuel Quality	0.13	2.7%
Stack Emission	0.11	2.2%
Catastrophe	0.10	2.0%
Inlet Air System and Compressors	0.10	1.9%
Boiler Piping System	0.09	1.8%
Condensing System	0.09	1.7%
Boiler Tube Fireside Slagging or Fouling	0.08	1.5%
Controls	0.07	1.5%
Exciter	0.07	1.5%
Generator	0.07	1.4%
Circulating Water Systems	0.07	1.3%
Miscellaneous (Steam Turbine)	0.07	1.3%
All Other Causes	0.97	19.2%
Total	5.06	100.0%

Table 5-18 Contributions to Economic Outages: 2010 (January through June) (See 2009 SOM, Table 5-20)

	Contribution to Economic Reasons
Lack of Fuel (OMC)	74.4%
Other Economic Problems	19.4%
Lack of Fuel (Non-OMC)	6.0%
Fuel Conservation	0.2%
Lack of Water (Hydro)	0.1%
Total	100.0%

Table 5-19 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2010 (January through June) (See 2009 SOM, Table 5-21)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	0.3%	0.0%	0.0%	0.0%	0.0%	27.0%	21.9%
Low Pressure Turbine	0.0%	0.0%	0.0%	0.0%	7.0%	0.5%	0.8%
Economic	0.7%	32.6%	11.5%	2.4%	0.0%	12.1%	11.9%
Electrical	8.7%	28.1%	5.2%	22.6%	29.6%	3.4%	6.7%
Boiler Air and Gas Systems	0.1%	0.0%	0.0%	0.0%	0.0%	7.1%	5.7%
Generator	13.3%	0.2%	0.1%	0.5%	0.0%	0.5%	1.4%
Boiler Fuel Supply from Bunkers to Boiler	0.0%	0.0%	0.0%	0.0%	0.0%	4.0%	3.3%
Fuel Quality	0.3%	0.0%	1.8%	0.0%	0.0%	3.3%	2.7%
Stack Emission	0.0%	0.0%	0.6%	0.0%	0.0%	2.7%	2.2%
Boiler Piping System	4.8%	0.0%	0.0%	0.0%	0.0%	1.9%	1.8%
Controls	0.1%	0.9%	0.2%	6.2%	2.5%	1.6%	1.5%
High Pressure Turbine	0.1%	0.0%	0.0%	0.0%	0.0%	1.0%	0.8%
Feedwater System	3.0%	0.0%	0.0%	0.0%	19.9%	2.4%	3.1%
Performance	0.0%	1.0%	0.0%	1.6%	0.0%	0.5%	0.5%
Condensing System	1.3%	0.0%	0.0%	0.0%	3.5%	1.8%	1.7%
Inlet Air System and Compressors	22.4%	3.8%	0.0%	0.0%	0.0%	0.0%	1.9%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.5%
Valve	0.8%	0.0%	0.0%	0.0%	0.4%	1.2%	1.0%
Miscellaneous (Generator)	2.5%	2.0%	0.4%	7.8%	1.3%	0.5%	0.8%
All Other Causes	41.8%	31.4%	80.1%	58.9%	35.9%	26.7%	28.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-20 Contribution to EFOF by unit type: Calendar year 2010 (January through June) (See 2009 SOM, Table 5-22)

	EFOF	Contribution to EFOF
Combined Cycle	2.7%	7.3%
Combustion Turbine	1.9%	6.3%
Diesel	3.8%	0.2%
Hydroelectric	0.6%	0.6%
Nuclear	1.2%	4.8%
Steam	7.5%	80.9%
Total	4.6%	100.0%

Outages Deemed Outside Management Control

Table 5-21 PJM EFORd vs. XEFORd: Calendar year 2010 (January through June) (See 2009 SOM, Table 5-23)

	2010 EFORd	2010 XEFORd	Difference
Combined Cycle	4.1%	4.0%	0.1%
Combustion Turbine	13.6%	8.9%	4.7%
Diesel	5.5%	3.9%	1.6%
Hydroelectric	1.1%	0.8%	0.2%
Nuclear	1.4%	1.4%	0.0%
Steam	9.8%	8.2%	1.6%
Total	7.8%	6.2%	1.5%

Components of EFORp

Table 5-22 Contribution to EFORp by unit type (Percentage points): 2009 to 2010 (January through June) (See 2009 SOM, Table 5-24)

	2009 (Jan - Jun)	2010 (Jan - Jun)
Combined Cycle	0.4	0.5
Combustion Turbine	0.5	0.3
Diesel	0.0	0.0
Hydroelectric	0.1	0.0
Nuclear	0.7	0.3
Steam	2.9	3.3
Total	4.6	4.4

Table 5-23 PJM EFORp data by unit type: 2009 to 2010 (January through June) (See 2009 SOM, Table 5-25)

	2009 (Jan - Jun)	2010 (Jan - Jun)
Combined Cycle	3.2%	3.9%
Combustion Turbine	3.4%	2.0%
Diesel	4.3%	3.9%
Hydroelectric	2.4%	0.4%
Nuclear	3.6%	1.5%
Steam	6.0%	6.7%
Total	4.6%	4.4%

EFORd, XEFORd and EFORp

Table 5-24 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2010 (January through June) (See 2009 SOM, Table 5-26)

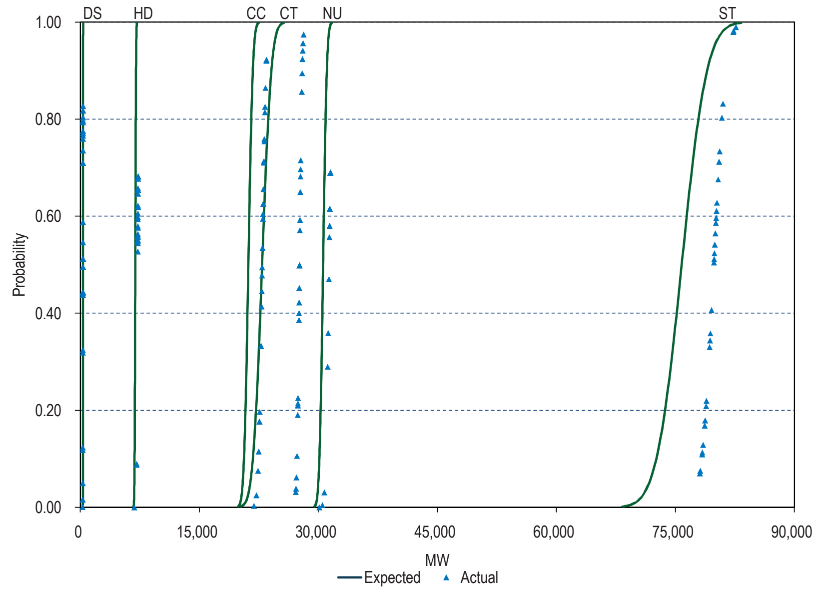
	EFORd	XEFORd	EFORp
Combined Cycle	0.5	0.5	0.5
Combustion Turbine	2.1	1.4	0.3
Diesel	0.0	0.0	0.0
Hydroelectric	0.0	0.0	0.0
Nuclear	0.3	0.3	0.3
Steam	4.8	4.0	3.3
Total	7.8	6.2	4.4

Table 5-25 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2010 (January through June) (See 2009 SOM, Table 5-27)

	EFORd	XEFORd	EFORp
Combined Cycle	4.1%	4.0%	3.9%
Combustion Turbine	13.6%	8.9%	2.0%
Diesel	5.5%	3.9%	3.9%
Hydroelectric	1.1%	0.8%	0.4%
Nuclear	1.4%	1.4%	1.5%
Steam	9.8%	8.2%	6.7%
Total	7.8%	6.2%	4.4%

Comparison of Expected and Actual Performance

Figure 5-7 PJM 2010 (January through June) distribution of EFORd data by unit type (See 2009 SOM, Figure 5-11)



Performance During Peak Months

Figure 5-8 PJM peak month data: 2010 (See 2009 SOM, Figure 5-12)

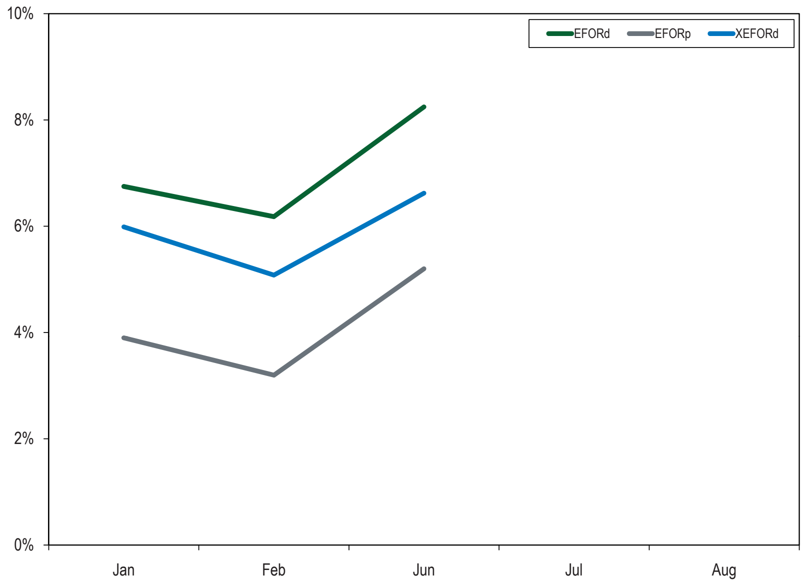
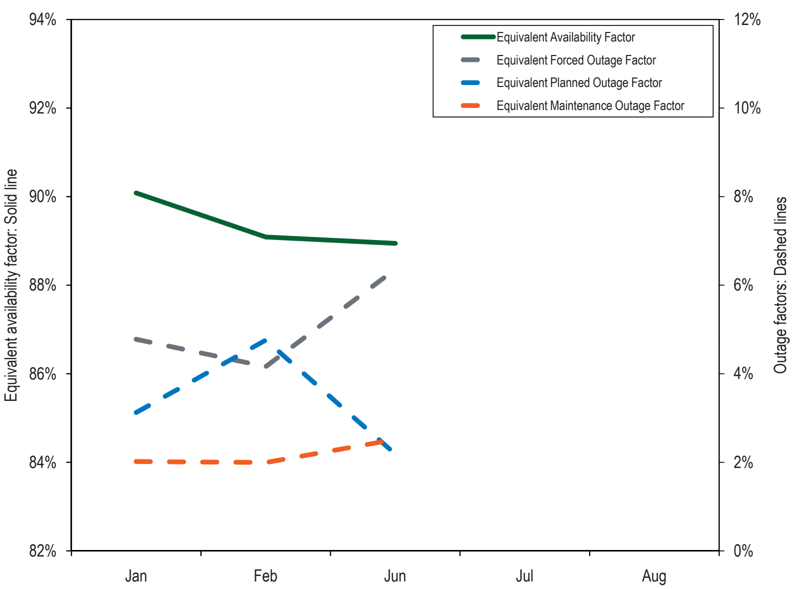


Figure 5-9 PJM peak month generator performance factors: 2010 (See 2009 SOM, Figure 5-13)



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 a cost basis.

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 *2009 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 the first six months of 2010.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[3] 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 the market clearing price.

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 2010.

Overview

Regulation Market

The PJM Regulation Market in 2010 continues 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. At the FERC's direction, the MMU prepared and submitted a report on November 30, 2009, on the impact of these changes.[4] The MMU also reported on the impact of these changes in the 2009 State of the Market Report.[5]

3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).
4 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>(465 KB).
5 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Market Structure

- **Supply.** During the first six months of 2010, the supply of offered and eligible regulation in PJM was generally 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 2010. The ratio of eligible regulation offered to regulation required averaged 3.01 for the first six months of 2010, almost identical to the 2009 ratio of 2.98.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements. The on-peak 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. Previously the requirement had been fixed daily at 1.0 percent of the daily forecast operating load. The average hourly regulation demand for the first six months of 2010 was 870 MW, compared to 844 MW for the first six months of 2009.

- **Market Concentration.** During the first six months of 2010, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1411 which is classified as "moderately concentrated."[6] The minimum hourly HHI was 761 and the maximum hourly HHI was 2983. The largest hourly market share in any single hour was 51 percent, and 79 percent of all hours had a maximum market share greater than 20 percent. For the first six months of 2010, 78 percent of hours had one or more pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market for the first six months of 2010 was characterized by structural market power in 78 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Beginning December 1, 2008, owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. Cost based offers are valid 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 cap.[7] In computing the market solution, PJM adds opportunity cost. 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. All units of owners who fail the three pivotal supplier test for an hour have their offers capped at the lesser of their cost based or price based offer. The regulation market is then re-solved.

  As part of the changes to the regulation market implemented on December 1, 2008, cost based offers may include a margin of $12.00 rather than the prior maximum margin of $7.50. The impact of this change was to increase cost based offer prices.

  As part of the changes to the regulation market implemented on December 1, 2008, PJM calculates opportunity costs using LMP forecasts and the lesser of the available price based offer or the most expensive available cost based offer as the reference, rather than the offer on which the unit is operating.[8] PJM adds this opportunity cost to the offers of the market participants. The impact of this change is to increase the regulation market clearing price in some hours.

Market Performance

- **Price.** For the PJM Regulation Market during the first six months of 2010, the load weighted, average price per MWh (the regulation market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $18.28. This was a decrease of $6.49, or 26 percent, from the average price for regulation during the first six months of 2009.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market during the first six months of 2010 were higher than they would have been in some hours but for the change to the definition of opportunity cost.

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

6 See the *2009 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).

7 See PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p.39.

8 See PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p. 59: "SPREGO utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation. "

Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

PJM made two significant changes to the Synchronized Reserve Market in 2009. These changes were intended to ensure that the synchronized reserve requirement accurately reflects the needs of PJM dispatch. This includes ensuring that the forecast amount of Tier 1 synchronized reserve is actually available to PJM dispatch during the operating hour. PJM changed the primary constraint which defines the Mid-Atlantic Subzone within the RFC Synchronized Reserve Market from Bedington—Black Oak to AP South. PJM reduced from 70 percent to 15 percent the percentage of Tier 1 available west of the AP South interface that it will consider as available to the Mid-Atlantic Subzone when it calculates the amount of Tier 2 required. These changes were made to address the fact that PJM Dispatch needed more synchronized reserve than was defined as the requirement to be met by the market. This problem has existed in the Synchronized Reserve Market since late 2007. These changes reduced the amount of additional, out of market, synchronized reserve required by PJM dispatch, which reduced opportunity cost payments and aligned the total cost of synchronized reserves more closely with Synchronized Reserve Market prices. Synchronized reserves added out of market were five percent of all synchronized reserves during the first six months of 2010, while they were 28 percent for the same time period in 2009. Opportunity cost payments accounted for 24 percent of total costs during the first six months of 2010 compared to 38 percent during the same time period in 2009.

Market Structure

- **Supply.** For the first six months of 2010, synchronized reserve offers were somewhat higher than the equivalent period in 2009. The offered and eligible excess supply ratio was 1.21 for the PJM Mid-Atlantic Synchronized Reserve Region.[9] For the RFC zone, the excess supply ratio was 2.33. The excess supply ratio is determined using the administratively required level of synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower than the required reserve level because there is usually a significant amount of Tier 1 synchronized reserve available. In the first six months of 2010, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,320 MW for the RFC Synchronized Reserve Zone and 1,171 MW for the Mid-Atlantic Subzone. Synchronized reserve demand in the Mid-Atlantic Subzone had been 1,150 MW until May 5 when the hourly requirement was changed to 1,200 MW. This change was made to accommodate a dynamically changing largest contingency for the AP South constraint. The only additional change was the declaration of double spinning for May 24 and 25 of 1,800 MW because of a planned outage. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared.

  Demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was normal in the first six months of 2010. In 22 percent of hours no Tier 2 synchronized reserve was needed. The average required Tier 2 (including self scheduled) was 387 MW.

  Synchronized reserves added out of market were three percent of all synchronized reserve during January through June of 2010. The amount of out of market synchronized reserves increased in June, and out of market synchronized reserve as a percentage of total purchased synchronized reserve increased sharply in June.

  As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, less than one percent of hours cleared a Tier 2 Synchronized Reserve Market in the RFC. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone for only four hours in the first six months of 2010. In the PJM Mid-Atlantic Synchronized Reserve Region, 78 percent of hours cleared a Tier 2 Synchronized Reserve Market. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 358 MW, although it was significantly lower in May and June. The average demand in May and June was at 272 MW. The lower demand for Tier 2 was the result of a larger supply of Tier 1 synchronized reserve. The demand was met by self scheduled synchronized reserves, which averaged 155 MW for the first six months, and cleared Tier 2 synchronized reserves, which averaged 203 MW for the first six months.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for the first six months of 2010

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

was 2981 which is classified as "highly concentrated."[10] For purchased synchronized reserve (cleared plus added) the HHI was 3034. During the first six months of 2010, in 58 percent of hours the maximum market share was greater than 40 percent (compared to 42 percent of hours in the first six months of 2009).

In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for the first six months of 2010, 45 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in the first six months of 2010, are 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.

  Demand side resources remained significant participants in the Synchronized Reserve Market in the first six months of 2010. In eight percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by demand side resources.

Market Performance

- **Price.** The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $8.60 per MW for the first six months of 2010, a $2.71 per MW increase from 2009.

- **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 during the first six months of 2010.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[11] 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.[12] 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.** For the first six months of 2010 the DASR Market had only one pivotal supplier hour.

Market Conduct

- **Withholding.** Economic withholding remains a problem in the DASR Market. Continuing a pattern seen since the inception of the DASR Market, a significant number of units offered at levels effectively guaranteed not to clear. Five percent of units offered at $50 or more and four percent of units offered at more than $900, in a market with an average clearing price of $0.06 and a maximum clearing price of $5.00.

- **DSR.** Demand side resources do participate in the DASR Market but remain insignificant.

Market Performance

- **Price.** For the first six months of 2010, the load weighted price of DASR was $0.06, including the 25 percent of hours when the market cleared at a price of $0.00.

10 See the *2009 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).

11 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

12 PJM Manual 13, Emergency Requirements, Revision 39, (January 1, 2010); pp 11-12.

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.[13]

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 for all costs associated with providing this service, as defined in the tariff. For 2009, charges were about $12.3 million. For the first six months of 2010 charges were $4.7 million. There was substantial zonal variation.

As a consequence of PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs of compliance with Critical Infrastructure Protection standards, black start costs likely will increase substantially. The revised filing also provides a better match between the sellers' commitment period and the cost recovery period.

The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

Conclusion

The MMU concludes that the results of the Regulation Market are not competitive. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market.[14] The results of the Regulation Market are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in offers greater than competitive offers in some hours and therefore in prices greater than competitive prices in some hours, and because the revised market rules are inconsistent with basic economic logic.[15] The competitive price is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct and consistent approach to the calculation of the opportunity cost. The offers from market participants are not at issue, as PJM directly calculates and adds opportunity costs to the offers of participants, following the revised market rules. The Regulation Market results are the result of the market design changes and are not the result of the behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test.

The MMU recommends that the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.

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.

The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU concludes that the DASR Market results were competitive in the first six months of 2010.

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.

13 PJM OATT Schedule § 1.3BB, Second Revised Second Revised Sheet No. 33.01, March 1, 2007.
14 See the *2009 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets."
15 The MMU has determined that the prior quantification of the impact on the clearing price of the changed calculation of opportunity cost is not correct. The MMU is working on improved calculations which will be made available when ready.

Overall, the MMU concludes that the Regulation Market results were not competitive in the first six months of 2010. The MMU concludes that the Synchronized Reserve Market results were competitive in the first six months of 2010. The MMU concludes that the DASR Market results were competitive in the first six months of 2010.

Regulation Market

Market Structure

Supply and Demand

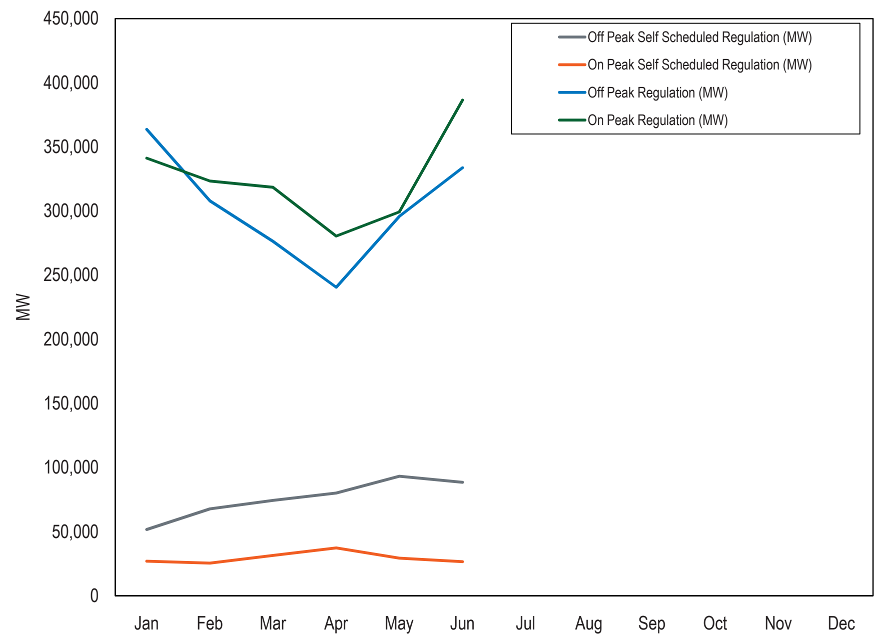
Table 6-1 PJM Regulation Market required MW and ratio of supply to requirement: January through June 2010 (See 2009 SOM, Table 6-1)

Month	Average Required Regulation (MW)	Ratio of Supply To Requirement
Jan	948	2.93
Feb	942	3.05
Mar	800	2.83
Apr	724	3.03
May	800	3.07
Jun	1,006	3.13

Table 6-2 PJM regulation capability, daily offer and hourly eligible: January through June 2010 (See 2009 SOM, Table 6-2)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,618	5,615	74%	2,605	34%
Off Peak	7,618			2,283	30%
On Peak	7,618			2,959	39%

Figure 6-1 Off peak and on peak regulation levels: January through June 2010 (See 2009 SOM, Figure 6-2)



Market Concentration

Table 6-3 PJM cleared regulation HHI: January through June 2010 (See 2009 SOM, Table 6-3)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, January - June, 2010	761	1411	2983

Figure 6-2 PJM Regulation Market HHI distribution: January through June 2010 (See 2009 SOM, Figure 6-1)

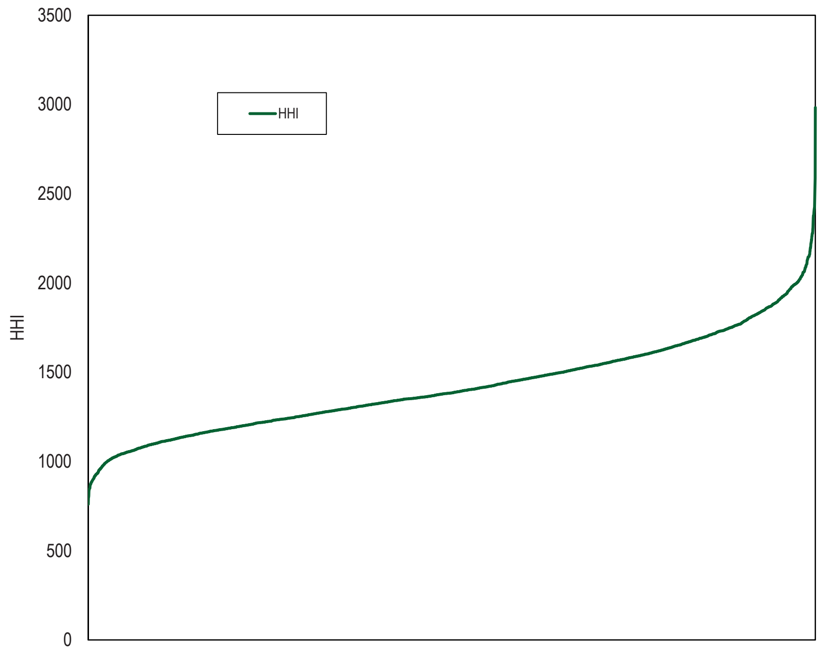


Table 6-4 Highest annual average hourly Regulation Market shares: January through June 2010 (See 2009 SOM, Table 6-4)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	16%
2	15%
3	9%
4	8%
5	7%

Table 6-5 Regulation market monthly three pivotal supplier results: January through June 2010 (See 2009 SOM, Table 6-5)

Month	Percent of Hours With Three Pivotal Suppliers
Jan	74%
Feb	70%
Mar	81%
Apr	82%
May	79%
Jun	81%

Table 6-6 Percent of hours when marginal unit supplier was pivotal: January through June 2010 (See 2009 SOM, Table 6-6)

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	66%
Feb	58%
Mar	71%
Apr	81%
May	79%
Jun	77%

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 2010 (See 2009 SOM, Figure 6-3)

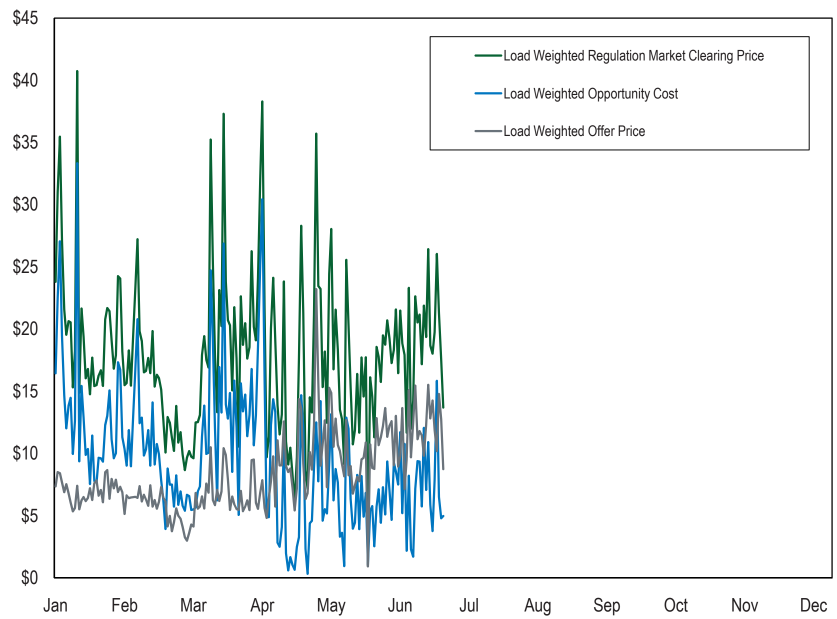


Figure 6-4 Monthly average regulation demand (required) vs. price: January through June 2010 (See 2009 SOM, Figure 6-4)

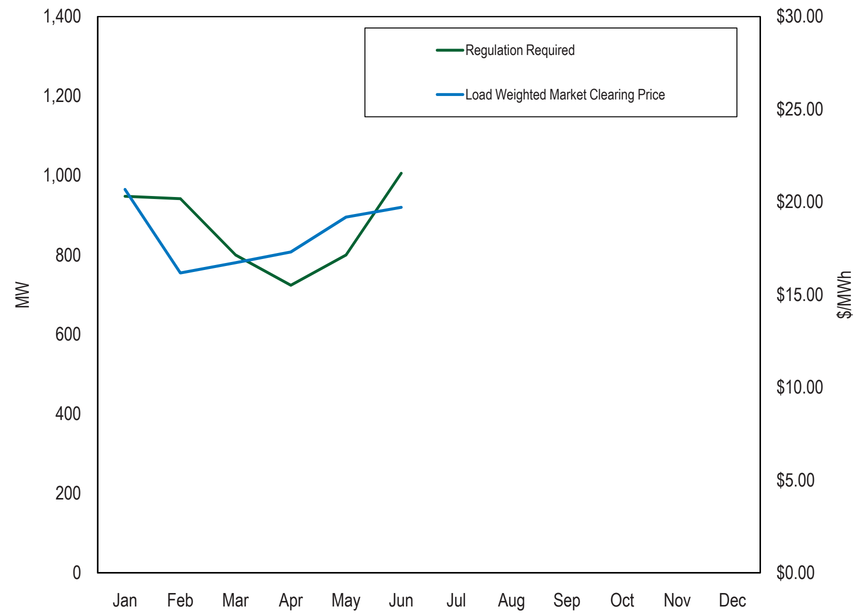


Figure 6-5 Monthly load weighted, average regulation cost and price: January through June 2010 (See 2009 SOM, Figure 6-5)

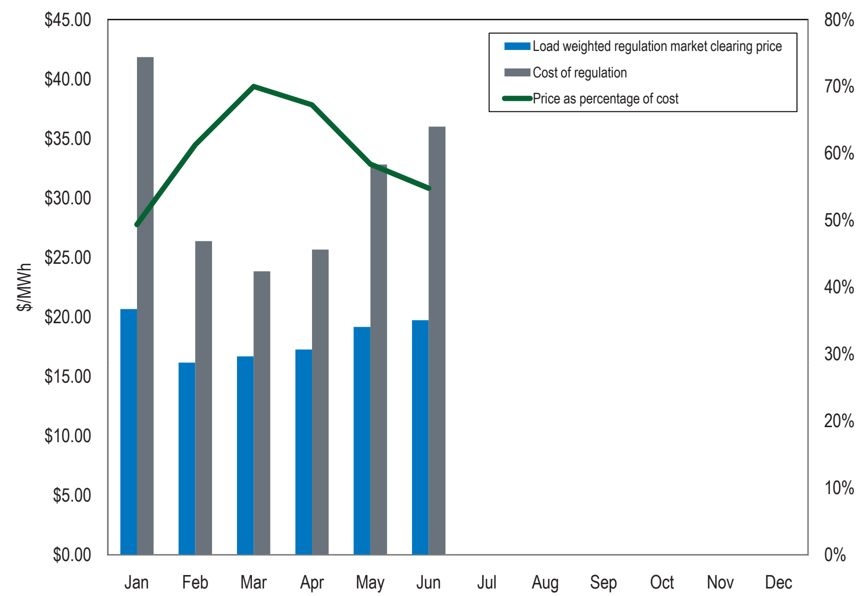


Table 6-7 Total regulation charges: January through June 2010 (See 2009 SOM, Table 6-7)

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price ($/MWh)	Cost of Regulation ($/MWh)
Jan	704,362	$29,479,645	$20.66	$41.85
Feb	632,007	$16,673,515	$16.17	$26.38
Mar	591,046	$14,058,674	$16.62	$23.79
Apr	594,378	$14,167,033	$16.69	$23.84
May	518,526	$13,307,387	$17.26	$25.66
Jun	588,452	$19,307,043	$19.16	$32.81
Jul	619,956	$22,320,781	$19.72	$36.00

Regulation Market Changes

Table 6-8 Summary of changes to Regulation Market design (See 2009 SOM, Table 6-8)

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.

TPS Testing

Table 6-9 Regulation Market pivotal supplier test results: December 2008 through June 2010 and December 2007 through June 2009 (See 2009 SOM, Table 6-9)

Year	Month	Percent of Hours With Three Pivotal Suppliers	Year	Month	Percent of Hours With Three Pivotal Suppliers
2008	Dec	92%	2007	Dec	79%
2009	Jan	84%	2008	Jan	84%
2009	Feb	61%	2008	Feb	83%
2009	Mar	42%	2008	Mar	89%
2009	Apr	39%	2008	Apr	88%
2009	May	31%	2008	May	97%
2009	Jun	37%	2008	Jun	77%
2009	Jul	39%	2008	Jul	75%
2009	Aug	35%	2008	Aug	80%
2009	Sep	47%	2008	Sep	74%
2009	Oct	64%	2008	Oct	89%
2009	Nov	62%	2008	Nov	59%
2009	Dec	80%	2008	Dec	92%
2010	Jan	74%	2009	Jan	84%
2010	Feb	70%	2009	Feb	61%
2010	Mar	83%	2009	Mar	42%
2010	Apr	82%	2009	Apr	39%
2010	May	79%	2009	May	31%
2010	Jun	81%	2009	Jun	37%

Synchronized Reserve Market

Market Structure

Demand

Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through June 2010 (See 2009 SOM, Figure 6-6)

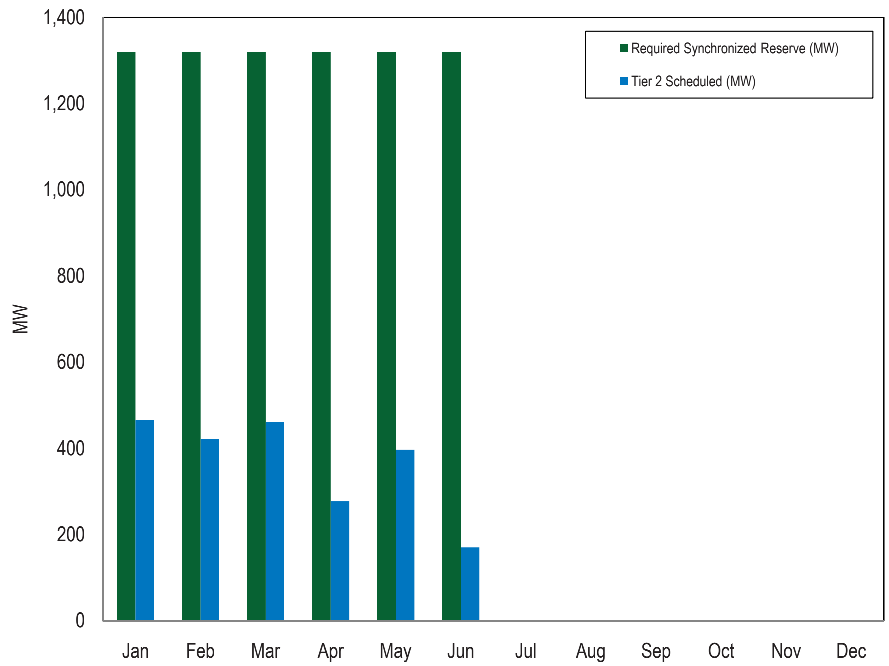
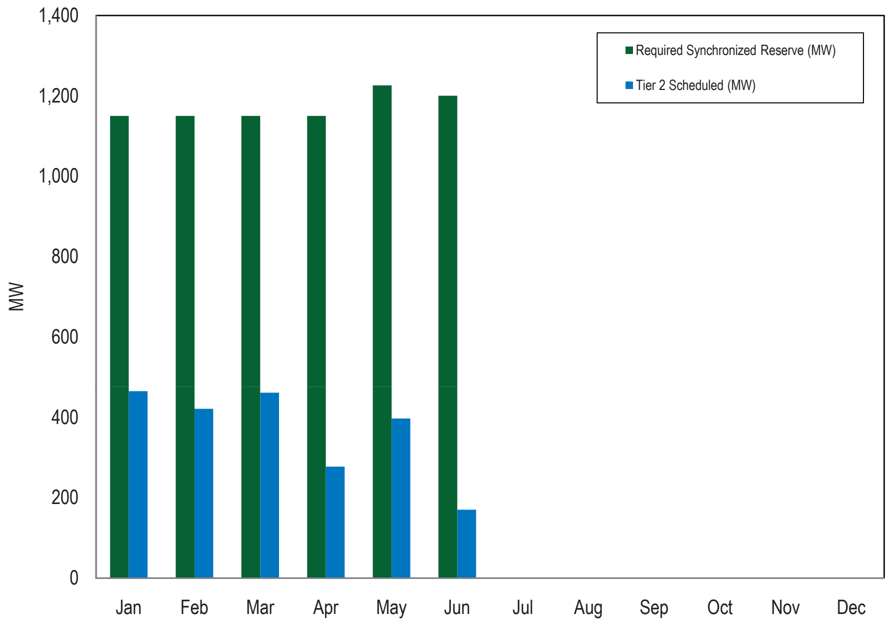


Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through June 2010 (See 2009 SOM, Figure 6-7)



Market Concentration

Figure 6-8 Purchased Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: January through June 2010 (See 2009 SOM, Figure 6-8)

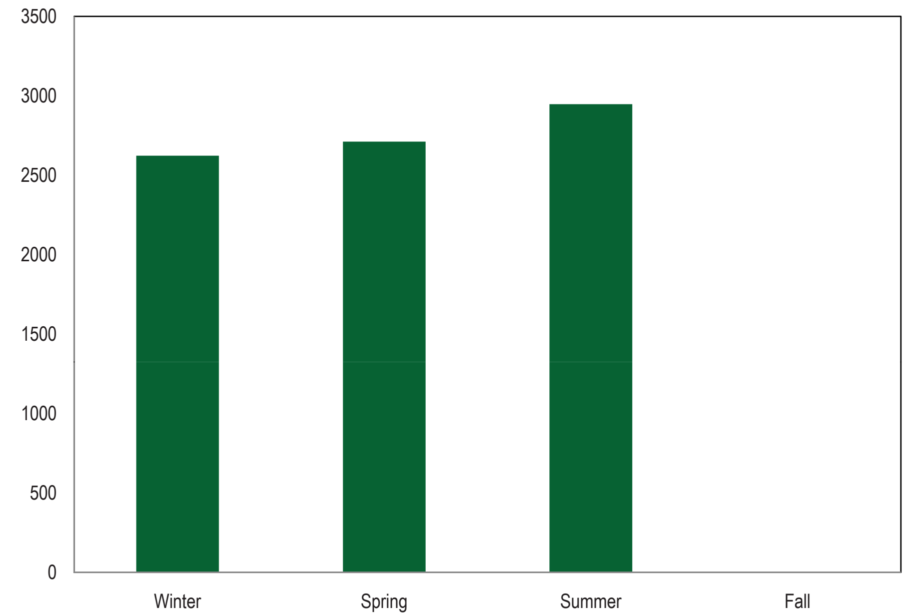


Table 6-10 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: January through June 2010 (See 2009 SOM, Table 6-15)

Company Market Share Rank	Cleared Synchronized Reserve Top Market Shares
1	32%
2	28%
3	25%
4	18%
5	18%

Market Conduct

Offers

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through June 2010 (See 2009 SOM, Figure 6-9)

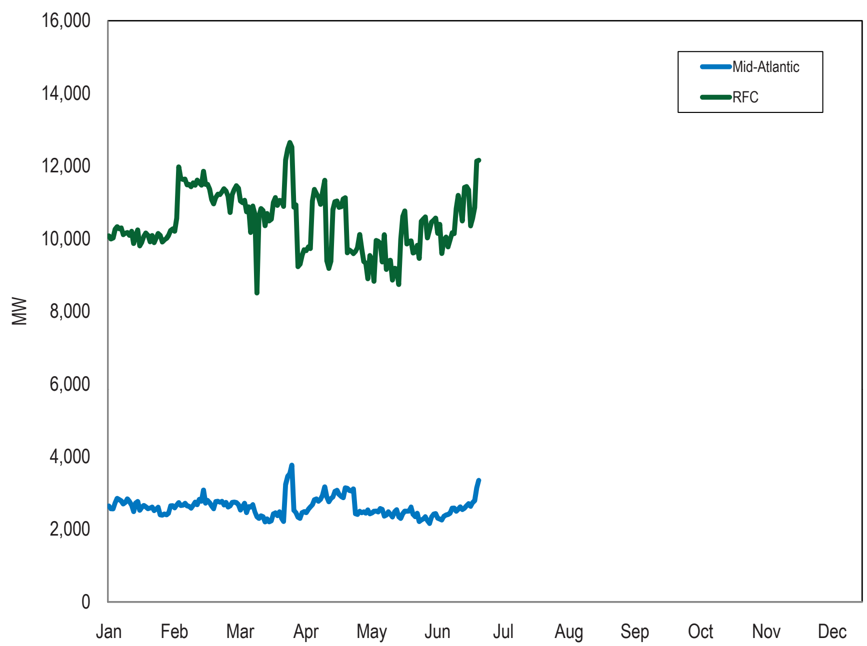
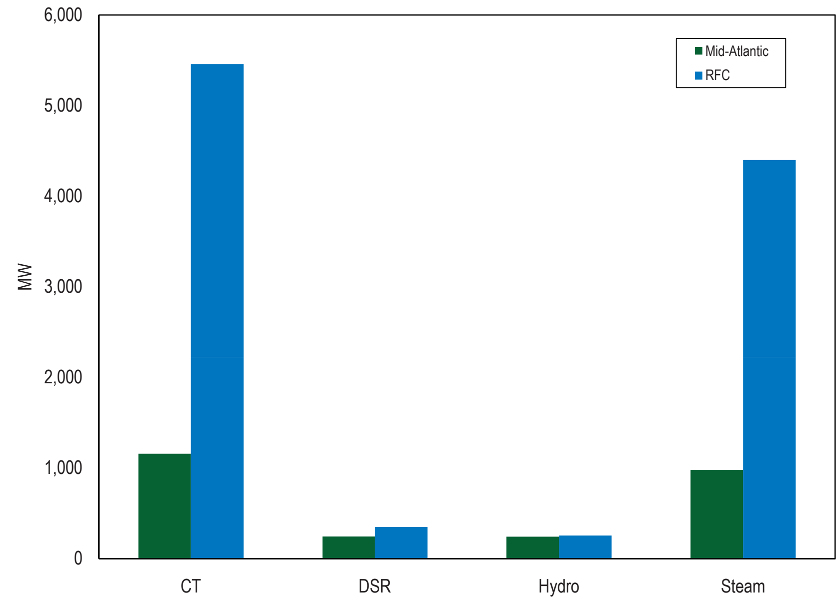


Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through June 2010 (See 2009 SOM, Figure 6-10)

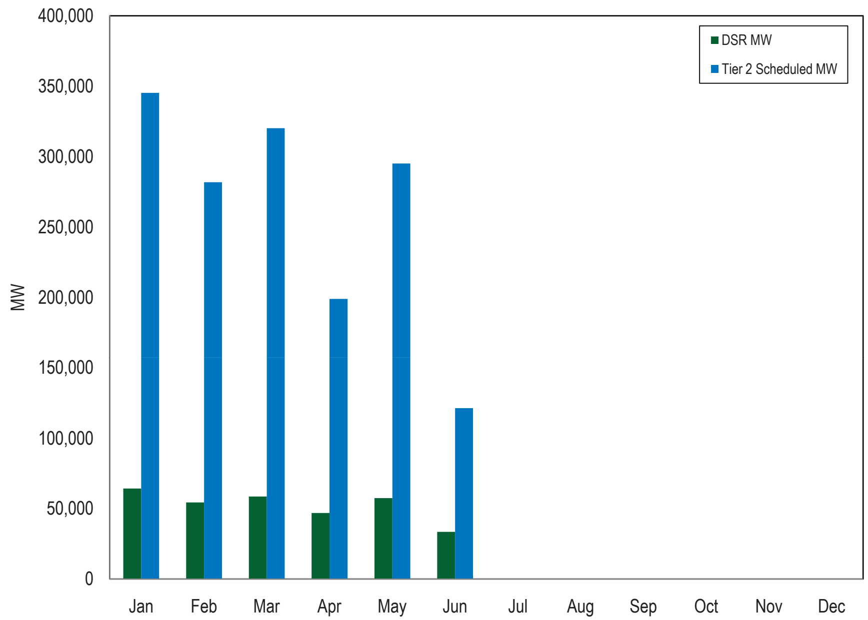


DSR

Table 6-11 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through June 2010 (See 2009 SOM, Table 6-16)

Month	Average SRMCP when all cleared synchronized reserve is DSR	Percent of scheduled synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$5.84	33%	$2.03	4%
Feb	$5.97	31%	$0.10	1%
Mar	$8.45	39%	$2.01	6%
Apr	$7.84	34%	$1.86	17%
May	$9.98	25%	$1.68	15%
Jun	$9.61	32%	$0.74	9%

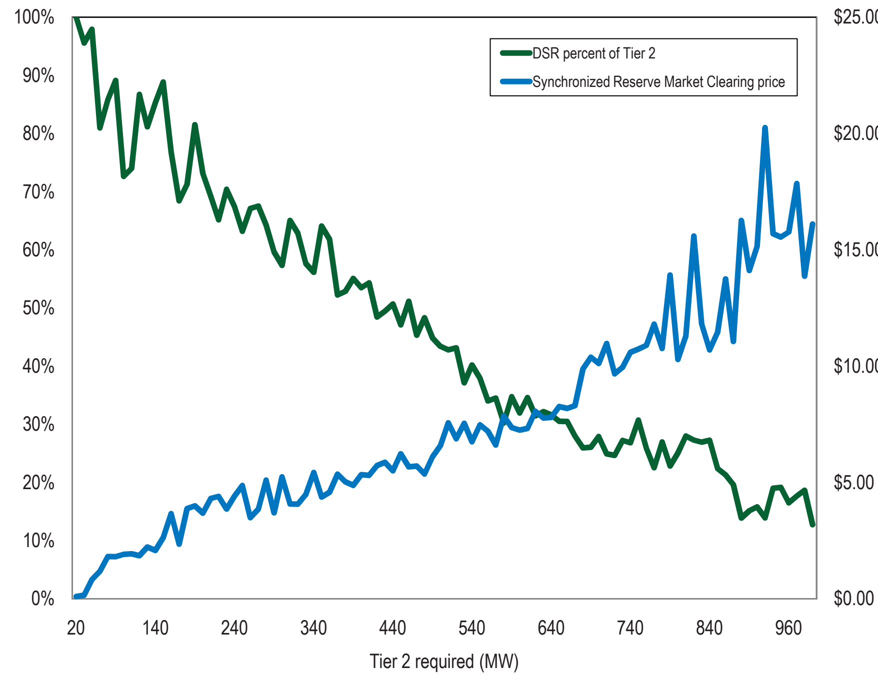
Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through June 2010 (See 2009 SOM, Figure 6-11)



Market Performance

Price

Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: January through June 2010 (See 2009 SOM, Figure 6-12)



Price and Cost

Figure 6-13 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through June 2010 (See 2009 SOM, Figure 6-13)

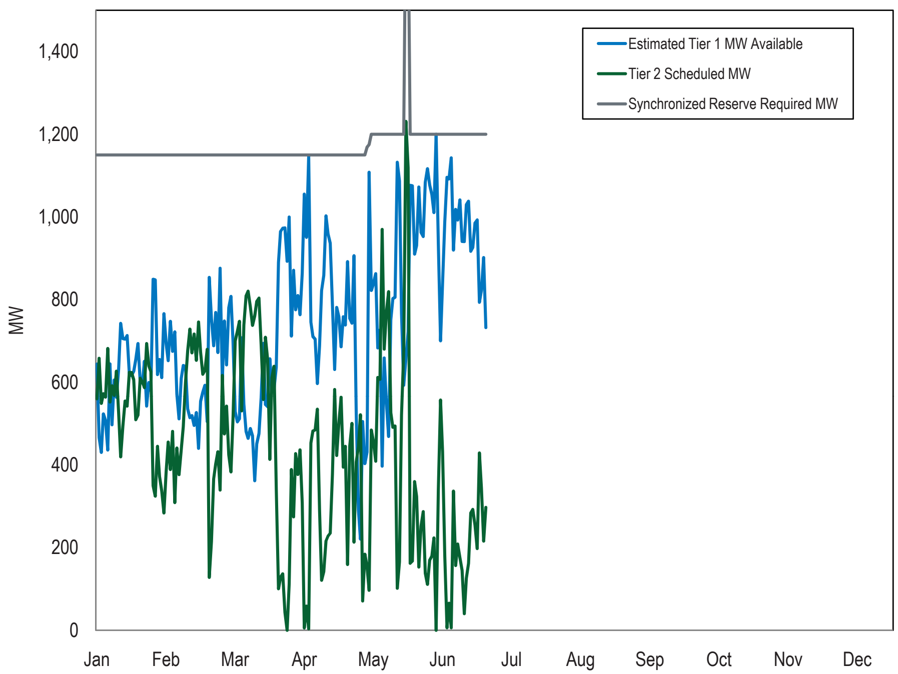


Figure 6-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through June 2010 (See 2009 SOM, Figure 6-14)

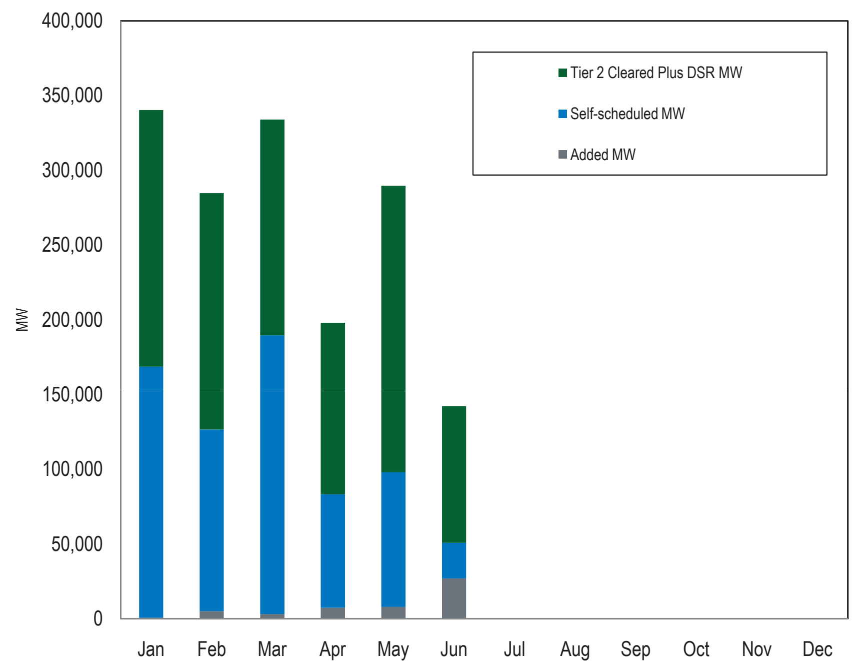


Figure 6-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through June 2010 (See 2009 SOM, Figure 6-15)

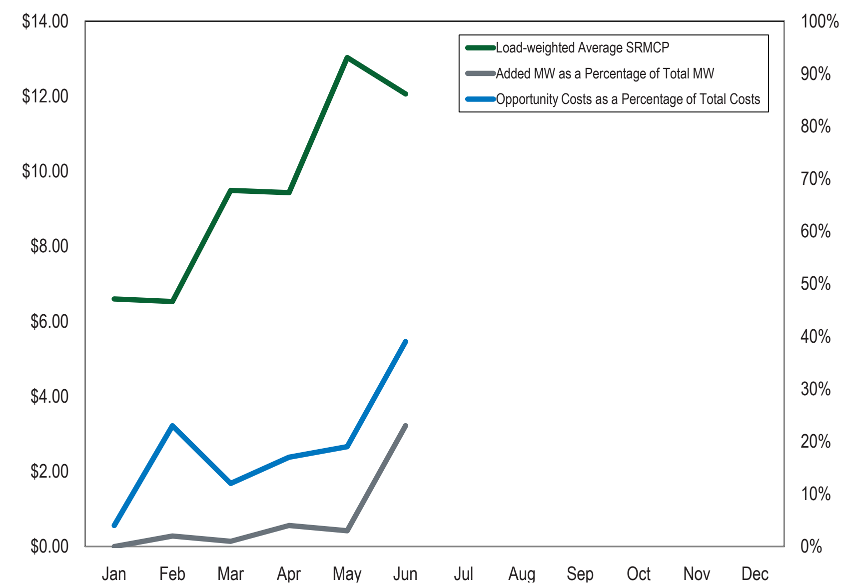
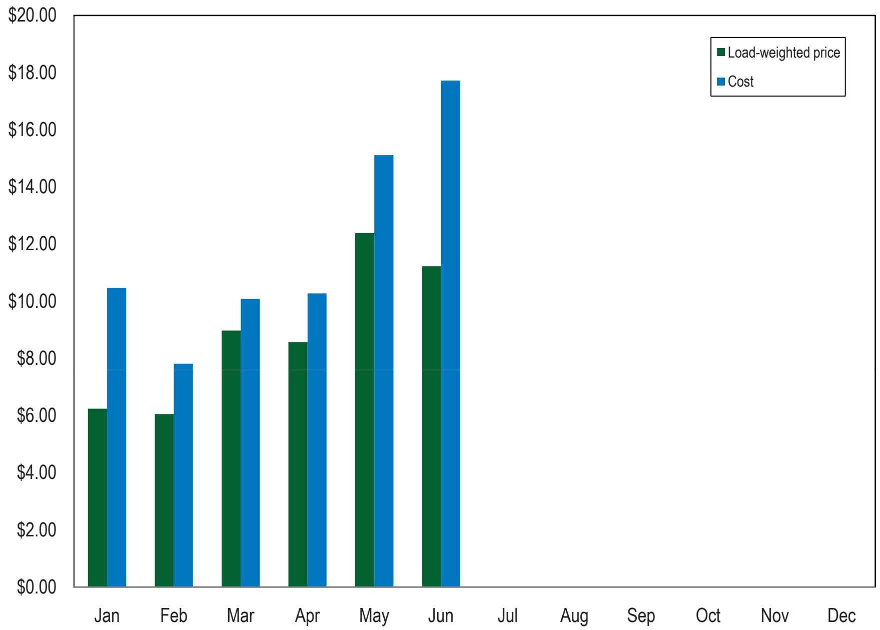


Figure 6-16 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): January through June 2010 (See 2009 SOM, Figure 6-16)



Day Ahead Scheduling Reserve (DASR)

Table 6-12 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through June 2010 (See 2009 SOM, Table 6-17)

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	6,246	$0.00	$0.75	$0.05	4,647,334	$242,018
Feb	6,191	$0.00	$0.50	$0.06	4,160,064	$228,087
Mar	5,441	$0.00	$0.50	$0.03	4,042,540	$109,862
Apr	4,871	$0.00	$0.42	$0.01	3,789,115	$45,352
May	5,487	$0.00	$2.00	$0.05	4,082,028	$164,277
Jun	6,864	$0.00	$5.00	$0.18	4,941,835	$833,865

Black Start Service

Table 6-13 Black Start yearly zonal charges for network transmission use: January through June 2010 (See 2009 SOM, Table 6-18)

Zone	Network Charges
AECO	$192,746
AEP	$365,817
AP	$67,719
BGE	$239,912
ComEd	$1,842,542
DAY	$72,781
DPL	$194,317
DLCO	$13,279
JCPL	$217,331
Met-Ed	$202,068
PECO	$361,431
PENELEC	$168,396
Pepco	$111,035
PPL	$77,082
PSEG	$471,501
UGI	$77,082

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 during the first six months of 2010.

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 *2009 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 increased by $237.3 million or 58 percent, from $408.2 million in the first six months of 2009 to $645.5 million in the first six months of 2010. Day-ahead congestion costs increased by $212.5 million or 41 percent, from $521.7 million in the first six months of 2009 to $734.2 million in the first six months of 2010. Balancing congestion costs increased by $24.9 million or 22 percent, from -$113.6 million in the first six months of 2009 to -$88.7 million in the first six months of 2010. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were four percent of total PJM billings in the first six months of 2010. Total PJM billings in the first six months of 2010 were $16.314 billion.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In the first six months of 2010, 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 2010 ranged from $20.4 million in March to $218.5 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 between eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface and other 500 kV constraints in the east. 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 the first six months of 2010.[3] Day-ahead congestion frequency increased from 2009 to 2010 by 7,746 congestion event hours or 21 percent. In the first six months of 2010, there were 43,818 day-ahead, congestion-event hours compared to 36,072 day-ahead, congestion-event hours in the first six months of 2009. Day-ahead, congestion-event hours increased on internal PJM interfaces, lines and transformers while congestion frequency on the reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) decreased. Real-time congestion frequency increased from 2009 to 2010 by 540 congestion event hours. In the first six months of 2010, there were 9,134 real-time, congestion-event hours compared to 8,594 real-time, congestion-event hours in the first six months of 2009. Real-time, congestion-event hours increased on the internal PJM interfaces and lines, while the reciprocally coordinated flowgates between PJM and the Midwest ISO, transmission and transformers saw decreases. The AP South Interface was the largest contributor to congestion costs in the first six months of 2010. With $234.2 million in total congestion costs, it accounted for 36 percent of the total PJM congestion costs in the first six months of 2010. The top five constraints in terms of congestion costs together contributed $418.1 million, or 65 percent, of the total PJM congestion in the first six months of 2010. The top five constraints included the AP South interface, the Bedington – Black Oak interface, the AEP-DOM interface, the 5004/5005 interface, and the Doubs transformer.

- **Zonal Congestion.** In the first six months of 2010, the Dominion Control Zone experienced the highest congestion costs of the control zones in PJM with $131.0 million. The AP South interface, the Bedington – Black Oak interface, the Pleasant View transformer, the Doubs transformer, and the Cloverdale – Lexington line contributed $87.4 million, or 67 percent of the total Dominion Control Zone congestion costs (Table 7-51). The AP Control Zone had the second highest congestion cost in PJM in the first six months of 2010. The $126.1 million in congestion costs in the AP Control Zone represented a 118 percent increase from the $57.8 million in congestion costs the zone had experienced in the first six months of 2009. The AP South interface contributed $57.2 million, or 45 percent of the total AP Control Zone congestion cost.

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.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non market mechanism, typically under traditional regulation. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[4] Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **Restructuring Responsibility for Grid Development.** FERC's recent decision in the *Primary Power* case and the currently pending *Central Transmission* case raise significant issues about the ownership of transmission, the resultant incentives to build new transmission facilities and the potential for competitive forces to reduce the cost of transmission.[5]

4 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).
5 131 FERC ¶ 61,015 (April 13, 2010); *Central Transmission, LLC v. PJM Interconnection, L.L.C.*, Docket No. EL10-52.

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 four percent of total PJM billings in the first six months of 2010. Total PJM billings in the first six months of 2010 were $16.314 billion. Total congestion costs increased by $237.3 million or 58 percent, from $408.2 million in the first six months of 2009 to $645.5 million in the first six months of 2010. Day-ahead congestion costs increased by $212.5 million or 41 percent, from $521.7 million in the first six months of 2009 to $734.2 million in the first six months of 2010. Balancing congestion costs increased by $24.9 million or 22 percent, from -$113.6 million in the first six months of 2009 to -$88.7 million in the first six months of 2010. Congestion costs were significantly higher in the Day-Ahead Market than in the balancing market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. Day-ahead congestion frequency increased from 2009 to 2010 by 7,746 congestion event hours or 21 percent. In the first six months of 2010, there were 43,818 day-ahead, congestion-event hours compared to 36,072 day-ahead, congestion event hours in the first six months of 2009. Real-time congestion frequency increased from 2009 to 2010 by 540 congestion event hours. In the first six months of 2010, there were 9,134 real-time, congestion event hours compared to 8,594 real-time, congestion event hours in the first six months of 2009.

ARRs and FTRs served as an effective, but not total, hedge against congestion. ARR and FTR revenues hedged more than 100 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2008 to 2009 planning period. For the 2009 to 2010 planning period, ARR and FTR revenue hedged 96.4 percent of the total congestion costs within PJM.[6] FTRs were paid at 96.9 percent of the target allocation level for the 12-month period of the 2009 to 2010 planning period, and at 97.8 percent of the target allocation level for the first month of the 2010 to 2011 planning period. Revenue adequacy for a planning period is not final until the end of the period.

There are other ways to evaluate the effectiveness of ARRs as a hedge. The value of ARRs and ARRs converted to self scheduled FTRs was 3.9 percent of total energy charges to load for the first six months of 2010.

One constraint accounted for 36 percent of total congestion costs in the first six months of 2010 and the top five constraints accounted for 65 percent of total congestion costs. The AP South Interface was the largest contributor to congestion costs in the first six months of 2010.

The congestion metric requires careful review. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[7] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. This is a cost only in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the system marginal price. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

6 See the *2010 Quarterly State of the Market Report for PJM: January through June*, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-23, "ARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010."

7 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

As an example, total congestion costs in PJM in the first six months of 2010 were $645.5 million, which was comprised of load congestion payments of $170.0 million, negative generation credits of $500.7 million and negative explicit congestion of $25.1 million (see Table 7-2).

Congestion

Total Calendar Year Congestion

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 through June 2010 (See 2009 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 (Jan - Jun)	$646	NA	$16,314	4%
Total	$9,591		$166,901	6%

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through June 2009 and 2010 (See 2009 SOM, Table 7-2)

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2009 (Jan - Jun)	$142.3	($301.8)	($35.9)	$408.2
2010 (Jan - Jun)	$170.0	($500.7)	($25.1)	$645.5

Monthly Congestion

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2008 through June 2010 (See 2009 SOM, Table 7-3)

	2008	2009	2010
Jan	$231.0	$149.3	$218.5
Feb	$168.1	$83.0	$106.4
Mar	$86.4	$74.6	$20.4
Apr	$126.2	$25.6	$42.6
May	$182.8	$25.9	$68.5
Jun	$436.4	$49.8	$189.1
Jul	$359.8	$39.4	
Aug	$127.4	$72.1	
Sep	$124.8	$23.9	
Oct	$102.2	$42.7	
Nov	$93.0	$36.3	
Dec	$78.4	$96.4	
Total	$2,116.6	$719.0	$645.5

Congestion Component of LMP

Table 7-4 Annual average congestion component of LMP: January through June 2009 and 2010 (See 2009 SOM, Table 7-4)

	2009 (Jan - Jun)		2010 (Jan - Jun)	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$2.61	$2.60	$2.14	$2.24
AEP	($2.41)	($2.38)	($3.52)	($3.81)
AP	$0.75	$1.79	($0.45)	($0.37)
BGE	$3.72	$3.49	$4.75	$4.72
ComEd	($6.40)	($7.26)	($5.95)	($6.74)
DAY	($3.37)	($3.22)	($4.25)	($4.52)
DLCO	($4.56)	($4.12)	($3.47)	($3.88)
Dominion	$2.93	$2.90	$5.20	$5.35
DPL	$2.92	$3.02	$2.26	$2.52
JCPL	$2.51	$2.72	$1.56	$1.79
Met-Ed	$2.69	$2.70	$2.22	$2.04
PECO	$2.43	$2.19	$1.87	$1.92
PENELEC	($0.01)	$0.09	($1.50)	($2.13)
Pepco	$3.67	$3.60	$5.75	$5.57
PPL	$2.46	$2.29	$1.58	$1.36
PSEG	$2.99	$3.17	$2.34	$2.96
RECO	$2.06	$2.21	$1.52	$1.25

Congested Facilities

Congestion by Facility Type and Voltage

Table 7-5 Congestion summary (By facility type): January through June 2010 (See 2009 SOM, Table 7-5)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	$1.9	($19.7)	$5.1	$26.7	($1.6)	$3.1	($16.2)	($20.8)	$5.8	3,471	939
Interface	$62.8	($330.6)	$3.7	$397.1	$10.2	$6.3	($2.3)	$1.5	$398.6	5,139	1,546
Line	$62.4	($139.8)	$23.8	$226.1	($15.0)	$6.8	($38.5)	($60.2)	$165.8	30,816	5,398
Transformer	$46.9	($27.8)	$3.0	$77.7	($0.4)	$2.7	($6.1)	($9.2)	$68.5	4,392	1,251
Unclassified	$2.7	($1.8)	$2.3	$6.7	$0.0	$0.0	$0.0	$0.0	$6.7	NA	NA
Total	$176.7	($519.6)	$37.9	$734.2	($6.7)	$18.9	($63.0)	($88.7)	$645.5	43,818	9,134

Table 7-6 Congestion summary (By facility type): January through June 2009 (See 2009 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	$12.4	($28.8)	$12.4	$53.6	($8.3)	$3.3	($51.8)	($63.4)	($9.8)	3,601	1,955
Interface	$31.1	($149.7)	$2.3	$183.1	$2.9	($1.8)	$1.3	$6.1	$189.2	2,580	837
Line	$58.5	($118.7)	$29.7	$206.9	($3.6)	$4.1	($23.2)	($30.9)	$176.0	25,915	4,197
Transformer	$55.2	($1.6)	$18.2	$75.0	($8.0)	($7.9)	($25.3)	($25.4)	$49.7	3,976	1,605
Unclassified	$2.2	($0.5)	$0.5	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	NA	NA
Total	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$408.2	36,072	8,594

Table 7-7 Congestion summary (By facility voltage): January through June 2010 (See 2009 SOM, Table 7-7)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.5	($1.8)	$0.5	$2.8	($1.1)	($0.1)	($3.2)	($4.2)	($1.4)	77	74
500	$72.7	($342.7)	$6.2	$421.6	$7.9	($0.7)	($10.7)	($2.1)	$419.5	5,999	2,304
345	$8.0	($42.5)	$8.7	$59.3	($5.4)	$5.4	($28.1)	($39.0)	$20.3	4,800	1,476
230	$32.8	($56.2)	$11.6	$100.7	($3.4)	$11.6	($13.3)	($28.3)	$72.3	9,294	1,684
138	$35.3	($75.7)	$8.4	$119.4	($2.9)	$1.7	($7.4)	($11.9)	$107.5	17,752	2,797
115	$21.4	$0.7	$0.2	$21.0	$0.4	$0.6	($0.3)	($0.5)	$20.4	2,319	665
69	$3.0	$0.3	$0.0	$2.8	($2.2)	$0.4	($0.1)	($2.7)	$0.1	3,324	134
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	37	0
12	$0.1	$0.1	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	216	0
Unclassified	$2.7	($1.8)	$2.3	$6.7	($0.0)	($0.0)	($0.0)	$0.0	$6.7	NA	NA
Total	$176.7	($519.6)	$37.9	$734.2	($6.7)	$18.9	($63.0)	($88.7)	$645.5	43,818	9,134

Table 7-8 Congestion summary (By facility voltage): January through June 2009 (See 2009 SOM, Table 7-8)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
500	$68.1	($165.3)	$10.6	$244.0	$1.2	($12.5)	($7.4)	$6.3	$250.3	5,455	1,704
345	$23.2	($34.4)	$29.7	$87.3	($4.2)	$2.0	($41.7)	($47.9)	$39.4	4,745	1,299
230	$15.0	($15.1)	$5.2	$35.2	$0.0	$3.6	($3.2)	($6.7)	$28.5	7,590	1,035
138	$42.9	($83.2)	$16.7	$142.8	($11.2)	$3.0	($46.3)	($60.5)	$82.3	14,093	3,987
115	$4.2	($1.4)	$0.3	$5.9	$0.4	$0.7	($0.2)	($0.6)	$5.3	2,133	345
69	$3.7	$0.4	$0.2	$3.5	($3.3)	$0.8	($0.1)	($4.2)	($0.8)	1,877	224
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
12	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	172	0
Unclassifed	$2.2	($0.5)	$0.5	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	NA	NA
Total	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$408.2	36,072	8,594

Constraint Duration

Table 7-9 Top 25 constraints with frequent occurrence: January through June 2009 and 2010 (See 2009 SOM, Table 7-9)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2009	2010	Change	2009	2010	Change	2009	2010	Change	2009	2010	Change
1	AP South	Interface	1,650	2,090	440	282	1,010	728	38%	48%	10%	6%	23%	17%
2	Athenia - Saddlebrook	Line	979	2,591	1,612	128	321	193	23%	60%	37%	3%	7%	4%
3	East Frankfort - Crete	Line	1,333	1,650	317	161	600	439	31%	38%	7%	4%	14%	10%
4	Waterman - West Dekalb	Line	911	1,496	585	28	223	195	21%	34%	13%	1%	5%	4%
5	Pleasant Valley - Belvidere	Line	1,534	1,277	(257)	210	220	10	35%	29%	(6%)	5%	5%	0%
6	5004/5005 Interface	Interface	334	1,050	716	198	367	169	8%	24%	16%	5%	8%	4%
7	Tiltonsville - Windsor	Line	794	1,127	333	198	270	72	18%	26%	8%	5%	6%	2%
8	Bedington - Black Oak	Interface	74	1,328	1,254	61	43	(18)	2%	31%	29%	1%	1%	(0%)
9	Pleasant Prairie - Zion	Flowgate	30	945	915	45	80	35	1%	22%	21%	1%	2%	1%
10	Danville - East Danville	Line	76	879	803	0	85	85	2%	20%	18%	0%	2%	2%
11	Cloverdale - Lexington	Line	666	578	(88)	239	341	102	15%	13%	(2%)	6%	8%	2%
12	Branchburg - Readington	Line	21	712	691	0	158	158	0%	16%	16%	0%	4%	4%
13	Lindenwold - Stratford	Line	194	840	646	0	0	0	4%	19%	15%	0%	0%	0%
14	Doubs	Transformer	36	536	500	13	283	270	1%	12%	12%	0%	7%	6%
15	Rising	Flowgate	0	776	776	3	36	33	0%	18%	18%	0%	1%	1%
16	Pinehill - Stratford	Line	859	794	(65)	0	0	0	20%	18%	(1%)	0%	0%	0%
17	Burlington - Croydon	Line	1,531	737	(794)	3	13	10	35%	17%	(18%)	0%	0%	0%
18	Crescent	Transformer	0	579	579	6	124	118	0%	13%	13%	0%	3%	3%
19	Marktown - Inland Steel	Flowgate	0	400	400	0	242	242	0%	9%	9%	0%	6%	6%
20	Bellehaven - Tasley	Line	23	616	593	0	0	0	1%	14%	14%	0%	0%	0%
21	Bayonne - PVSC	Line	371	578	207	0	0	0	9%	13%	5%	0%	0%	0%
22	Leonia - New Milford	Line	2,164	568	(1,596)	30	1	(29)	50%	13%	(37%)	1%	0%	(1%)
23	AEP-DOM	Interface	101	471	370	57	84	27	2%	11%	9%	1%	2%	1%
24	Sammis - Wylie Ridge	Line	622	494	(128)	101	44	(57)	14%	11%	(3%)	2%	1%	(1%)
25	Hawthorn - Waldwick	Line	0	454	454	0	38	38	0%	10%	10%	0%	1%	1%

Table 7-10 Top 25 constraints with largest year-to-year change in occurrence: January through June 2009 and 2010 (See 2009 SOM, Table 7-10)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2009	2010	Change	2009	2010	Change	2009	2010	Change	2009	2010	Change
1	Kammer	Transformer	1,554	0	(1,554)	726	0	(726)	36%	0%	(36%)	17%	0%	(17%)
2	Dunes Acres - Michigan City	Flowgate	1,713	142	(1,571)	671	3	(668)	39%	3%	(36%)	15%	0%	(15%)
3	Athenia - Saddlebrook	Line	979	2,591	1,612	128	321	193	23%	60%	37%	3%	7%	4%
4	Leonia - New Milford	Line	2,164	568	(1,596)	30	1	(29)	50%	13%	(37%)	1%	0%	(1%)
5	Bedington - Black Oak	Interface	74	1,328	1,254	61	43	(18)	2%	31%	29%	1%	1%	(0%)
6	AP South	Interface	1,650	2,090	440	282	1,010	728	38%	48%	10%	6%	23%	17%
7	Kammer - Ormet	Line	552	0	(552)	509	0	(509)	13%	0%	(13%)	12%	0%	(12%)
8	Pleasant Prairie - Zion	Flowgate	30	945	915	45	80	35	1%	22%	21%	1%	2%	1%
9	Danville - East Danville	Line	76	879	803	0	85	85	2%	20%	18%	0%	2%	2%
10	5004/5005 Interface	Interface	334	1,050	716	198	367	169	8%	24%	16%	5%	8%	4%
11	Pana North	Flowgate	581	0	(581)	300	0	(300)	13%	0%	(13%)	7%	0%	(7%)
12	Ruth - Turner	Line	639	22	(617)	270	11	(259)	15%	1%	(14%)	6%	0%	(6%)
13	Branchburg - Readington	Line	21	712	691	0	158	158	0%	16%	16%	0%	4%	4%
14	Rising	Flowgate	0	776	776	3	36	33	0%	18%	18%	0%	1%	1%
15	Burlington - Croydon	Line	1,531	737	(794)	3	13	10	35%	17%	(18%)	0%	0%	0%
16	Waterman - West Dekalb	Line	911	1,496	585	28	223	195	21%	34%	13%	1%	5%	4%
17	Doubs	Transformer	36	536	500	13	283	270	1%	12%	12%	0%	7%	6%
18	East Frankfort - Crete	Line	1,333	1,650	317	161	600	439	31%	38%	7%	4%	14%	10%
19	Crescent	Transformer	0	579	579	6	124	118	0%	13%	13%	0%	3%	3%
20	Lindenwold - Stratford	Line	194	840	646	0	0	0	4%	19%	15%	0%	0%	0%
21	Oak Grove - Galesburg	Flowgate	400	61	(339)	377	72	(305)	9%	1%	(8%)	9%	2%	(7%)
22	Marktown - Inland Steel	Flowgate	0	400	400	0	242	242	0%	9%	9%	0%	6%	6%
23	Wylie Ridge	Transformer	354	27	(327)	335	53	(282)	8%	1%	(8%)	8%	1%	(6%)
24	Bellehaven - Tasley	Line	23	616	593	0	0	0	1%	14%	14%	0%	0%	0%
25	Plainsboro - Trenton	Line	389	0	(389)	164	0	(164)	9%	0%	(9%)	4%	0%	(4%)

Constraint Costs

Table 7-11 Top 25 constraints affecting annual PJM congestion costs (By facility): January through June 2010 (See 2009 SOM, Table 7-11)

				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
1	AP South	Interface	500	$9.8	($222.4)	$2.3	$234.5	$6.8	$5.3	($1.8)	($0.3)	$234.2	36%
2	Bedington - Black Oak	Interface	500	$10.6	($50.1)	$1.1	$61.8	$0.1	($0.9)	($0.5)	$0.5	$62.3	10%
3	AEP-DOM	Interface	500	$9.8	($37.6)	$0.9	$48.3	$0.1	($1.3)	($0.1)	$1.3	$49.6	8%
4	5004/5005 Interface	Interface	500	$28.6	($19.5)	($0.7)	$47.4	$2.8	$2.5	$0.0	$0.3	$47.7	7%
5	Doubs	Transformer	AP	$16.8	($10.5)	$0.7	$28.0	($0.4)	$1.1	($2.1)	($3.6)	$24.4	4%
6	East Frankfort - Crete	Line	ComEd	$4.2	($20.8)	$2.9	$27.9	($2.8)	$0.9	($5.5)	($9.2)	$18.7	3%
7	Cloverdale - Lexington	Line	AEP	$7.3	($5.8)	$1.3	$14.4	($1.9)	($2.0)	($3.4)	($3.2)	$11.2	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	Pleasant Valley - Belvidere	Line	ComEd	($5.5)	($16.1)	$1.3	$11.8	($0.1)	$2.1	($2.1)	($4.3)	$7.5	1%
10	Limerick	Transformer	PECO	$1.1	($2.2)	($0.1)	$3.2	$0.8	($3.4)	($0.1)	$4.1	$7.3	1%
11	Tiltonsville - Windsor	Line	AP	$7.7	($0.2)	$0.2	$8.1	($1.3)	$0.0	$0.3	($1.1)	$7.1	1%
12	Graceton - Raphael Road	Line	BGE	($2.5)	($7.6)	$0.6	$5.8	$0.6	($0.7)	($0.2)	$1.1	$6.8	1%
13	Unclassified	Unclassified	Unclassified	$2.7	($1.8)	$2.3	$6.7	$0.0	$0.0	$0.0	$0.0	$6.7	1%
14	Mount Storm - Pruntytown	Line	AP	$1.3	($2.7)	$0.1	$4.1	$0.7	($3.3)	($1.5)	$2.4	$6.5	1%
15	Pleasant View	Transformer	Dominion	($0.1)	($0.4)	$0.0	$0.3	($2.3)	$3.6	($0.3)	($6.3)	($6.0)	(1%)
16	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($2.8)	($7.0)	$2.1	$6.3	($0.4)	$1.1	($10.4)	($12.0)	($5.7)	(1%)
17	Branchburg - Readington	Line	PSEG	$2.4	($4.6)	$0.3	$7.3	($0.5)	$1.4	($0.0)	($1.9)	$5.4	1%
18	Rising	Flowgate	Midwest ISO	$0.2	($4.3)	$0.6	$5.1	($0.0)	($0.0)	($0.0)	($0.0)	$5.1	1%
19	Reid - Ringgold	Line	AP	($0.2)	($4.9)	$0.3	$4.9	$0.0	($0.0)	($0.0)	$0.0	$5.0	1%
20	Nipetown - Reid	Line	AP	$1.2	($3.1)	$0.2	$4.5	($0.0)	($0.1)	($0.1)	$0.0	$4.5	1%
21	Hunterstown	Transformer	Met-Ed	$2.1	($2.0)	$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	($1.2)	($5.8)	($0.7)	$3.9	$0.1	$0.1	$0.1	$0.1	$4.0	1%
25	Seward	Transformer	PENELEC	$10.2	$6.0	($0.1)	$4.1	($0.1)	$0.0	$0.0	($0.1)	$4.0	1%

Table 7-12 Top 25 constraints affecting annual PJM congestion costs (By facility): January through June 2009 (See 2009 SOM, Table 7-12)

				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	2009
1	AP South	Interface	500	$6.4	($106.1)	$0.5	$113.0	$2.3	($2.7)	$1.9	$6.9	$119.9	29%
2	West	Interface	500	$17.8	($21.4)	$0.6	$39.7	$0.3	($0.1)	($0.1)	$0.4	$40.1	10%
3	5004/5005 Interface	Interface	500	$5.6	($15.7)	$0.8	$22.1	$0.9	$0.3	$0.1	$0.6	$22.7	6%
4	Kammer	Transformer	500	$28.2	$9.4	$6.4	$25.1	($2.2)	($6.1)	($6.9)	($2.9)	$22.2	5%
5	Mount Storm - Pruntytown	Line	AP	$1.8	($16.8)	$0.5	$19.1	$1.1	($0.8)	($0.2)	$1.7	$20.8	5%
6	East Frankfort - Crete	Line	ComEd	$4.5	($11.7)	$7.0	$23.2	($0.6)	$0.0	($3.3)	($3.9)	$19.3	5%
7	Pleasant Valley - Belvidere	Line	ComEd	($2.7)	($20.9)	$2.4	$20.5	$0.7	$1.6	($3.5)	($4.5)	$16.0	4%
8	Cloverdale - Lexington	Line	AEP	$6.2	($4.0)	$1.5	$11.7	($0.0)	($2.7)	($1.9)	$0.7	$12.4	3%
9	Pana North	Flowgate	Midwest ISO	$0.1	($1.6)	$1.2	$2.9	($0.4)	$1.0	($11.5)	($13.0)	($10.1)	(2%)
10	Ruth - Turner	Line	AEP	$2.4	($6.3)	$0.5	$9.2	($1.3)	($0.7)	($0.6)	($1.2)	$8.0	2%
11	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.5	($8.3)	$2.5	$13.2	($0.7)	$0.4	($4.3)	($5.4)	$7.9	2%
12	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$9.5	($14.4)	$6.8	$30.7	($5.4)	($1.2)	($19.8)	($24.0)	$6.7	2%
13	Kanawha River	Transformer	AEP	$2.0	($3.6)	$0.3	$5.8	$0.1	($0.5)	($0.1)	$0.5	$6.3	2%
14	Kammer - Ormet	Line	AEP	$4.3	($4.1)	($0.1)	$8.3	($1.6)	$0.5	($0.0)	($2.2)	$6.2	2%
15	Sammis - Wylie Ridge	Line	AP	$3.1	($2.7)	$3.4	$9.2	($0.8)	($0.3)	($2.6)	($3.2)	$6.0	1%
16	Tiltonsville - Windsor	Line	AP	$5.6	($0.4)	$0.4	$6.4	($0.3)	($0.6)	($0.9)	($0.6)	$5.8	1%
17	Kanawha - Kincaid	Line	AEP	$1.9	($3.5)	$0.2	$5.6	$0.0	$0.0	$0.0	$0.0	$5.6	1%
18	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	(1%)
19	Kanawha River - Bradley	Line	AEP	($0.1)	($4.6)	$0.3	$4.7	($0.0)	$0.1	($0.0)	($0.1)	$4.7	1%
20	Breed - Wheatland	Line	AEP	($0.1)	($4.2)	$0.5	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	1%
21	Mount Storm	Transformer	AP	$0.8	($3.9)	($0.1)	$4.7	($0.2)	($0.2)	($0.1)	($0.1)	$4.5	1%
22	Bedington - Black Oak	Interface	500	$0.7	($3.7)	$0.1	$4.5	($0.4)	($0.0)	$0.2	($0.3)	$4.2	1%
23	Glidden - West Dekalb	Line	ComEd	($0.3)	($4.0)	$0.3	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1%
24	Graceton - Raphael Road	Line	BGE	$0.9	($2.2)	$0.4	$3.4	$1.0	$0.3	($0.5)	$0.2	$3.6	1%
25	Sliver Lake - Cherry Valley	Line	ComEd	($0.1)	($3.9)	$0.8	$4.6	$0.6	$0.3	($1.4)	($1.2)	$3.4	1%

Congestion-Event Summary for Midwest ISO Flowgates

Table 7-13 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through June 2010 (See 2009 SOM, Table 7-13)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pleasant Prairie - Zion	($2.8)	($7.0)	$2.1	$6.3	($0.4)	$1.1	($10.4)	($12.0)	($5.7)	945	80
2	Rising	$0.2	($4.3)	$0.6	$5.1	($0.0)	($0.0)	($0.0)	($0.0)	$5.1	776	36
3	Crete - St Johns Tap	$0.3	($3.9)	$0.1	$4.4	($0.2)	$0.2	($0.8)	($1.1)	$3.2	330	82
4	Palisades - Vergennes	$2.8	($0.6)	$0.5	$3.9	($0.1)	$0.4	($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)	$0.7	($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	($0.1)	$0.1	($0.2)	($0.3)	($0.3)	0	30

Table 7-14 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through June 2009 (See 2009 SOM, Table 7-14)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pana North	$0.1	($1.6)	$1.2	$2.9	($0.4)	$1.0	($11.5)	($13.0)	($10.1)	581	300
2	Crete - St Johns Tap	$2.5	($8.3)	$2.5	$13.2	($0.7)	$0.4	($4.3)	($5.4)	$7.9	539	132
3	Dunes Acres - Michigan City	$9.5	($14.4)	$6.8	$30.7	($5.4)	($1.2)	($19.8)	($24.0)	$6.7	1,713	671
4	Schahfer - Burr Oak	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	62	81
5	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.6	($2.2)	($2.7)	($2.7)	0	128
6	Pleasant Prairie - Zion	($0.0)	($0.2)	$0.2	$0.3	$0.3	$0.6	($2.0)	($2.3)	($1.9)	30	45
7	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($1.1)	($1.3)	($1.3)	0	44
8	Oak Grove - Galesburg	($0.4)	($2.6)	$0.2	$2.4	$0.6	$1.1	($3.1)	($3.6)	($1.1)	400	377
9	State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	($0.4)	($0.6)	($0.6)	0	30
10	Lanesville	$0.2	($0.1)	$0.1	$0.4	$0.0	$0.1	($0.8)	($0.9)	($0.5)	65	32
11	Pawnee	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.4)	($0.4)	($0.4)	0	35
12	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.3	($0.0)	($0.4)	($0.4)	0	4
13	State Line - Wolf Lake	$0.1	($0.2)	$0.2	$0.4	($0.0)	($0.0)	($0.2)	($0.2)	$0.3	109	17
14	Bunsonville - Eugene	$0.0	($0.1)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
15	Burr Oak	$0.1	($0.2)	$0.4	$0.7	($0.2)	$0.0	($0.6)	($0.9)	($0.2)	24	37

Congestion-Event Summary for the 500 kV System

Table 7-15 Regional constraints summary (By facility): January through June 2010 (See 2009 SOM, Table 7-15)

				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	$9.8	($222.4)	$2.3	$234.5	$6.8	$5.3	($1.8)	($0.3)	$234.2	2,090	1,010
2	Bedington - Black Oak	Interface	500	$10.6	($50.1)	$1.1	$61.8	$0.1	($0.9)	($0.5)	$0.5	$62.3	1,328	43
3	AEP-DOM	Interface	500	$9.8	($37.6)	$0.9	$48.3	$0.1	($1.3)	($0.1)	$1.3	$49.6	471	84
4	5004/5005 Interface	Interface	500	$28.6	($19.5)	($0.7)	$47.4	$2.8	$2.5	$0.0	$0.3	$47.7	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	82	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	$1.1	($0.8)	$0.3	$2.2	($0.4)	($0.5)	($0.6)	($0.5)	$1.7	79	92
8	Central	Interface	500	$0.2	($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

Table 7-16 Regional constraints summary (By facility): January through June 2009 (See 2009 SOM, Table 7-16)

				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	$6.4	($106.1)	$0.5	$113.0	$2.3	($2.7)	$1.9	$6.9	$119.9	1,650	282
2	West	Interface	500	$17.8	($21.4)	$0.6	$39.7	$0.3	($0.1)	($0.1)	$0.4	$40.1	391	55
3	5004/5005 Interface	Interface	500	$5.6	($15.7)	$0.8	$22.1	$0.9	$0.3	$0.1	$0.6	$22.7	334	198
4	Kammer	Transformer	500	$28.2	$9.4	$6.4	$25.1	($2.2)	($6.1)	($6.9)	($2.9)	$22.2	1,554	726
5	Bedington - Black Oak	Interface	500	$0.7	($3.7)	$0.1	$4.5	($0.4)	($0.0)	$0.2	($0.3)	$4.2	74	61
6	AEP-DOM	Interface	500	$0.5	($2.7)	$0.3	$3.5	($0.5)	($0.0)	($0.3)	($0.8)	$2.7	101	57
7	East	Interface	500	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	11	0
8	Central	Interface	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	$0.1	19	8
9	Harrison - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	4

Zonal Congestion

Summary

Table 7-17 Congestion cost summary (By control zone): January through June 2010 (See 2009 SOM, Table 7-17)

	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	($55.3)	($151.4)	$5.6	$101.6	($9.0)	$7.6	($8.1)	($24.7)	$76.9
AP	($12.3)	($143.9)	$0.1	$131.7	$6.7	$10.9	($1.4)	($5.6)	$126.1
BGE	$78.5	$57.3	$3.2	$24.5	$6.6	($4.5)	($3.3)	$7.8	$32.2
ComEd	($179.3)	($299.6)	($0.0)	$120.2	($6.5)	$8.6	($5.8)	($20.8)	$99.4
DAY	($7.0)	($12.6)	$1.9	$7.5	$0.2	$1.0	($2.7)	($3.4)	$4.1
DLCO	($41.9)	($70.2)	($0.1)	$28.2	($4.3)	($1.0)	($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	$144.6	$8.9	$7.5	$143.1	($4.8)	($0.8)	($8.0)	($12.0)	$131.0
External	($54.3)	($64.0)	($1.9)	$7.7	$8.3	($6.2)	($14.6)	($0.1)	$7.6
JCPL	$18.8	$4.6	$0.2	$14.5	$1.2	($0.4)	($0.3)	$1.3	$15.8
Met-Ed	$19.9	$12.9	$0.3	$7.3	$0.1	($0.2)	($0.2)	$0.0	$7.4
PECO	$21.1	$29.4	$0.0	($8.2)	$0.2	($2.5)	($0.0)	$2.7	($5.6)
PENELEC	($42.3)	($91.3)	($0.1)	$48.9	$11.6	$3.9	$0.2	$7.8	$56.7
PPL	$32.5	$37.5	$1.3	($3.7)	$3.4	$2.1	($0.0)	$1.2	($2.5)
PSEG	$45.4	$33.5	$15.7	$27.6	($7.1)	$7.8	($13.9)	($28.9)	($1.3)
Pepco	$172.3	$119.1	$3.9	$57.1	($13.5)	($7.7)	($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	$176.7	($519.6)	$37.9	$734.2	($6.7)	$18.9	($63.0)	($88.7)	$645.5

Table 7-18 Congestion cost summary (By control zone): January through June 2009 (See 2009 SOM, Table 7-18)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$14.5	$5.8	$0.2	$8.9	($0.6)	$0.7	$0.4	($0.9)	$8.0
AEP	($32.1)	($91.3)	$7.9	$67.1	($3.9)	$4.0	($9.7)	($17.6)	$49.5
AP	$20.5	($48.7)	$10.5	$79.7	($4.0)	($0.6)	($18.5)	($21.9)	$57.8
BGE	$52.5	$44.5	$0.7	$8.7	$4.6	($3.3)	($0.7)	$7.2	$15.9
ComEd	($147.7)	($280.3)	($2.1)	$130.5	($5.3)	$1.1	($1.0)	($7.4)	$123.1
DAY	($6.0)	($11.0)	$0.1	$5.0	$0.6	$1.4	($0.2)	($0.9)	$4.1
DLCO	($33.2)	($52.4)	($0.0)	$19.2	($2.9)	$3.8	($0.1)	($6.7)	$12.5
DPL	$31.2	$10.0	$0.3	$21.5	($2.2)	$1.1	($0.3)	($3.6)	$17.8
Dominion	$52.8	($2.3)	$4.9	$59.9	$0.6	($3.5)	($4.8)	($0.8)	$59.2
External	($13.7)	($36.7)	$28.1	$51.2	($1.4)	($2.6)	($57.6)	($56.4)	($5.3)
JCPL	$32.1	$12.4	$0.0	$19.8	($0.1)	($2.1)	($0.1)	$1.9	$21.6
Met-Ed	$23.9	$23.5	$0.2	$0.6	($0.2)	($0.4)	($0.3)	($0.1)	$0.5
PECO	$9.4	$23.4	$0.1	($13.9)	($0.1)	$0.8	($0.1)	($1.0)	($14.9)
PENELEC	($1.9)	($20.6)	$0.3	$19.0	$1.8	$1.6	($0.2)	$0.1	$19.1
PPL	$8.1	$12.2	$1.9	($2.1)	$0.1	($0.8)	$0.2	$1.1	($1.0)
PSEG	$50.6	$40.7	$8.4	$18.3	($0.7)	$3.9	($4.4)	($9.0)	$9.3
Pepco	$96.7	$71.4	$1.5	$26.8	($3.2)	($7.5)	($1.4)	$2.8	$29.6
RECO	$1.6	$0.0	$0.1	$1.6	($0.1)	($0.0)	($0.1)	($0.2)	$1.4
Total	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$408.2

Details of Regional and Zonal Congestion

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-19 AECO Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 SOM, Table 7-19)

				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	England - Middletap	Line	AECO	$3.4	$0.7	$0.0	$2.7	($0.4)	($0.4)	($0.0)	($0.0)	$2.7	293	69
2	5004/5005 Interface	Interface	500	$4.1	$1.9	$0.0	$2.2	$0.3	($0.0)	($0.0)	$0.3	$2.5	1,050	367
3	Absecon - Lewis	Line	AECO	$0.2	$0.0	$0.0	$0.2	($1.5)	$0.1	($0.1)	($1.6)	($1.4)	81	18
4	Graceton - Raphael Road	Line	BGE	($1.1)	($0.5)	($0.0)	($0.6)	($0.0)	$0.1	$0.0	($0.1)	($0.8)	197	99
5	AP South	Interface	500	$1.0	$0.5	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.1	$0.6	2,090	1,010
6	East Frankfort - Crete	Line	ComEd	$0.6	$0.2	$0.0	$0.4	$0.1	($0.0)	($0.0)	$0.1	$0.6	1,650	600
7	Bedington - Black Oak	Interface	500	$0.9	$0.4	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	1,328	43
8	Branchburg - Readington	Line	PSEG	($0.6)	($0.2)	($0.0)	($0.4)	($0.0)	$0.0	$0.0	($0.0)	($0.4)	712	158
9	Doubs	Transformer	AP	$0.4	$0.1	$0.0	$0.3	$0.2	$0.0	($0.0)	$0.2	$0.4	536	283
10	Cloverdale - Lexington	Line	AEP	$0.3	$0.1	$0.0	$0.2	$0.1	$0.0	($0.0)	$0.1	$0.3	578	341
11	Athenia - Saddlebrook	Line	PSEG	($0.3)	($0.1)	($0.0)	($0.2)	($0.1)	$0.0	$0.0	($0.1)	($0.3)	2,591	321
12	Corson - Court	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.0)	($0.3)	($0.3)	7	15
13	Tiltonsville - Windsor	Line	AP	$0.4	$0.1	$0.0	$0.3	$0.1	$0.0	($0.0)	$0.1	$0.3	1,127	270
14	Limerick	Transformer	PECO	$0.3	$0.1	$0.0	$0.2	$0.1	($0.0)	$0.0	$0.1	$0.3	53	18
15	West	Interface	500	$0.3	$0.1	$0.0	$0.2	$0.1	$0.0	$0.0	$0.1	$0.2	82	41
19	Monroe	Transformer	AECO	$0.1	$0.0	($0.0)	$0.1	$0.1	($0.0)	$0.0	$0.1	$0.2	16	9
38	Lewis - Motts - Cedar	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	25	0
54	Sherman	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	5
73	Shieldalloy - Vineland	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	5
94	Lindenwold - Stratford	Line	AECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	840	0

Table 7-20 AECO Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 SOM, Table 7-20)

				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	$4.6	$2.2	$0.0	$2.4	$0.0	($0.0)	($0.0)	$0.0	$2.4	391	55
2	Kammer	Transformer	500	$2.1	$0.8	$0.0	$1.3	$0.1	($0.0)	$0.0	$0.2	$1.5	1,554	726
3	5004/5005 Interface	Interface	500	$1.9	$0.9	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	334	198
4	Wylie Ridge	Transformer	AP	$1.8	$0.9	$0.0	$0.9	($0.0)	$0.1	$0.1	($0.0)	$0.9	354	335
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.8	$0.2	$0.0	$0.7	$0.1	($0.0)	$0.0	$0.2	$0.8	1,713	671
6	Absecon - Lewis	Line	AECO	$1.0	$0.1	$0.0	$1.0	($1.2)	$0.5	($0.0)	($1.7)	($0.8)	22	149
7	Graceton - Raphael Road	Line	BGE	($0.7)	($0.2)	($0.0)	($0.5)	$0.1	$0.1	$0.0	$0.0	($0.5)	174	90
8	AP South	Interface	500	$0.7	$0.4	$0.0	$0.4	$0.0	$0.0	$0.1	$0.1	$0.5	1,650	282
9	Sammis - Wylie Ridge	Line	AP	$0.6	$0.2	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.4	622	101
10	East Frankfort - Crete	Line	ComEd	$0.5	$0.1	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	1,333	161
11	Tiltonsville - Windsor	Line	AP	$0.4	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.1	$0.3	794	198
12	Atlantic - Larrabee	Line	JCPL	($0.3)	($0.0)	$0.0	($0.3)	($0.1)	($0.0)	$0.0	($0.0)	($0.3)	188	45
13	Cloverdale - Lexington	Line	AEP	$0.4	$0.2	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.1	$0.3	666	239
14	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.3	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.3	539	132
15	Lewis - Motts - Cedar	Line	AECO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	108	0
16	Monroe	Transformer	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	134	11
33	Shieldalloy - Vineland	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	11	13
49	Carlls Corner - Sherman Ave	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	20	0
53	Clayton - Williams	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
82	Monroe - New Freedom	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	69	0

BGE Control Zone

Table 7-21 BGE Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 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	AP South	Interface	500	$29.4	$23.5	$1.3	$7.2	$2.7	($1.4)	($1.2)	$2.9	$10.1	2,090	1,010
2	Bedington - Black Oak	Interface	500	$13.0	$10.0	$0.5	$3.4	$0.3	($0.2)	($0.1)	$0.5	$3.9	1,328	43
3	Doubs	Transformer	AP	$6.2	$4.7	$0.1	$1.6	$0.8	($1.2)	($0.3)	$1.7	$3.3	536	283
4	Brandon Shores - Riverside	Line	BGE	$2.4	($1.1)	$0.0	$3.5	($0.5)	$0.2	($0.1)	($0.7)	$2.8	73	55
5	5004/5005 Interface	Interface	500	$4.7	$2.5	$0.3	$2.5	$0.3	($0.2)	($0.2)	$0.3	$2.7	1,050	367
6	Graceton - Raphael Road	Line	BGE	$4.9	$3.2	$0.3	$2.0	$0.2	($0.5)	($0.3)	$0.4	$2.4	197	99
7	Mount Storm - Pruntytown	Line	AP	$0.6	$0.5	$0.0	$0.2	$0.5	($0.3)	($0.2)	$0.7	$0.9	87	244
8	Cloverdale - Lexington	Line	AEP	$2.0	$2.0	$0.1	$0.1	$0.6	($0.3)	($0.2)	$0.7	$0.9	578	341
9	East Frankfort - Crete	Line	ComEd	$1.8	$1.4	$0.1	$0.4	$0.2	($0.1)	($0.0)	$0.3	$0.7	1,650	600
10	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	($0.0)	($0.2)	$0.6	$0.1	($0.7)	($0.7)	31	101
11	AEP-DOM	Interface	500	$3.1	$2.8	$0.1	$0.3	$0.2	($0.0)	($0.0)	$0.2	$0.6	471	84
12	West	Interface	500	$0.8	$0.5	$0.0	$0.3	$0.2	($0.1)	($0.0)	$0.2	$0.5	82	41
13	Fullerton - Windyedge	Line	BGE	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	23	0
14	Branchburg - Readington	Line	PSEG	($0.8)	($0.5)	($0.1)	($0.4)	($0.1)	$0.1	$0.1	($0.0)	($0.4)	712	158
15	Tiltonsville - Windsor	Line	AP	$1.0	$0.8	$0.0	$0.3	$0.1	($0.1)	($0.1)	$0.1	$0.4	1,127	270
30	Glenarm - Windy Edge	Line	BGE	$0.2	$0.1	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	15	13
37	Green Street - Westport	Line	BGE	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	44	0
42	East Point - Riverside	Line	BGE	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	6	5
70	Graceton - Safe Harbor	Line	BGE	$0.2	$0.1	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	15	2
85	Conastone - Graceton	Line	BGE	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.0	$0.0	0	3

Table 7-22 BGE Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	AP South	Interface	500	$14.1	$13.5	$0.1	$0.7	$1.2	($0.9)	($0.1)	$2.0	$2.7	1,650	282
2	Kammer	Transformer	500	$6.2	$5.0	$0.1	$1.3	$0.7	($0.5)	($0.2)	$1.0	$2.4	1,554	726
3	West	Interface	500	$8.1	$6.8	$0.2	$1.4	$0.1	($0.1)	($0.0)	$0.2	$1.6	391	55
4	Wylie Ridge	Transformer	AP	$3.6	$3.4	$0.1	$0.3	$0.6	($0.7)	($0.2)	$1.2	$1.5	354	335
5	5004/5005 Interface	Interface	500	$1.4	$0.8	$0.1	$0.6	$0.2	($0.2)	($0.1)	$0.4	$1.0	334	198
6	Graceton - Raphael Road	Line	BGE	$2.9	$2.0	$0.0	$1.0	$0.1	$0.1	($0.1)	($0.1)	$0.9	174	90
7	Mount Storm - Pruntytown	Line	AP	$3.2	$2.9	$0.0	$0.2	$0.4	($0.2)	($0.0)	$0.6	$0.8	523	25
8	Pumphrey - Westport	Line	Pepco	$0.5	($0.1)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	573	0
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.1	$1.8	$0.0	$0.3	$0.3	($0.0)	($0.0)	$0.3	$0.6	1,713	671
10	Cloverdale - Lexington	Line	AEP	$2.2	$2.0	$0.0	$0.2	$0.2	($0.1)	($0.0)	$0.3	$0.5	666	239
11	Sammis - Wylie Ridge	Line	AP	$1.4	$1.1	$0.0	$0.3	$0.1	($0.1)	($0.0)	$0.1	$0.4	622	101
12	Tiltonsville - Windsor	Line	AP	$0.8	$0.6	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.3	794	198
13	East Frankfort - Crete	Line	ComEd	$1.2	$1.0	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.3	1,333	161
14	Five Forks - Rock Ridge	Line	BGE	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	55	0
15	Bedington - Black Oak	Interface	500	$0.8	$0.7	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.1	$0.2	74	61
16	Waugh Chapel	Transformer	BGE	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	$0.0	$0.2	$0.2	0	8
17	Conastone	Transformer	BGE	$0.3	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	17	1
56	Glenarm - Windy Edge	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0
76	Green Street - Westport	Line	BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	151	0
78	Concord - Green Street	Line	BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0

DPL Control Zone

Table 7-23 DPL Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 SOM, Table 7-23)

				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	$7.8	$2.4	$0.0	$5.4	$0.3	$0.2	($0.0)	$0.1	$5.5	1,050	367
2	AP South	Interface	500	$3.1	$1.2	$0.0	$1.9	$0.1	$0.0	($0.0)	$0.1	$2.0	2,090	1,010
3	Bedington - Black Oak	Interface	500	$1.9	$0.8	$0.0	$1.2	$0.0	$0.0	($0.0)	($0.0)	$1.2	1,328	43
4	East Frankfort - Crete	Line	ComEd	$1.2	$0.2	$0.0	$1.0	$0.0	$0.0	($0.0)	$0.0	$1.0	1,650	600
5	Graceton - Raphael Road	Line	BGE	($2.0)	($1.0)	($0.0)	($1.0)	($0.0)	($0.1)	$0.0	$0.0	($1.0)	197	99
6	Oak Hall	Transformer	DPL	$1.0	$0.2	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	220	0
7	Indian River At20	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.3	($0.6)	($0.0)	$0.9	$0.9	0	8
8	Doubs	Transformer	AP	$0.8	$0.2	$0.0	$0.6	$0.1	($0.0)	($0.1)	$0.0	$0.7	536	283
9	Cloverdale - Lexington	Line	AEP	$0.6	$0.1	$0.0	$0.5	$0.1	$0.0	($0.1)	$0.0	$0.5	578	341
10	Branchburg - Readington	Line	PSEG	($0.9)	($0.4)	($0.0)	($0.5)	($0.0)	($0.0)	$0.0	$0.0	($0.5)	712	158
11	Longwood - Wye Mills	Line	DPL	$0.5	$0.1	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	92	0
12	Tiltonsville - Windsor	Line	AP	$0.7	$0.2	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	1,127	270
13	Sammis - Wylie Ridge	Line	AP	$0.5	$0.1	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	494	44
14	Athenia - Saddlebrook	Line	PSEG	($0.6)	($0.1)	($0.0)	($0.5)	($0.0)	($0.0)	$0.1	$0.1	($0.4)	2,591	321
15	West	Interface	500	$0.6	$0.2	$0.0	$0.3	$0.1	$0.1	($0.0)	$0.0	$0.4	82	41
16	Middletown - Mt Pleasant	Line	DPL	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	43	0
17	New Church - Piney Grove	Line	DPL	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	116	0
18	Cecil - Colora	Line	DPL	$0.7	$0.1	$0.1	$0.6	($0.1)	$0.1	($0.1)	($0.3)	$0.3	82	18
20	Cecil - Glassgow	Line	DPL	$0.3	$0.1	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	34	0
24	Bellehaven - Tasley	Line	DPL	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	616	0

Table 7-24 DPL Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	West	Interface	500	$8.6	$3.6	$0.0	$5.1	($0.0)	$0.0	($0.0)	($0.1)	$5.0	391	55
2	Kammer	Transformer	500	$4.1	$1.0	$0.0	$3.2	($0.1)	$0.1	($0.0)	($0.3)	$2.9	1,554	726
3	Short - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.2	($0.1)	($2.4)	($2.4)	0	27
4	Wylie Ridge	Transformer	AP	$3.4	$1.3	$0.0	$2.1	$0.2	$0.2	($0.0)	($0.0)	$2.1	354	335
5	5004/5005 Interface	Interface	500	$3.7	$1.5	$0.0	$2.2	$0.0	$0.2	($0.1)	($0.3)	$2.0	334	198
6	AP South	Interface	500	$2.0	$0.6	$0.0	$1.4	$0.0	$0.1	($0.0)	($0.1)	$1.4	1,650	282
7	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.5	$0.2	($0.0)	$1.3	($0.1)	$0.0	$0.0	($0.1)	$1.3	1,713	671
8	Sammis - Wylie Ridge	Line	AP	$1.2	$0.2	$0.0	$1.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.9	622	101
9	East Frankfort - Crete	Line	ComEd	$0.9	$0.2	($0.0)	$0.8	$0.0	$0.0	$0.0	($0.0)	$0.8	1,333	161
10	Cloverdale - Lexington	Line	AEP	$0.9	$0.2	$0.0	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.6	666	239
11	Church - I.B. Corners	Line	DPL	$0.7	$0.1	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.0)	$0.6	45	5
12	Tiltonsville - Windsor	Line	AP	$0.7	$0.1	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.1)	$0.5	794	198
13	Graceton - Raphael Road	Line	BGE	($1.3)	($0.3)	($0.0)	($1.0)	$0.3	($0.3)	$0.0	$0.5	($0.5)	174	90
14	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.5	$0.0	($0.0)	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	539	132
15	Edgemoor - Harmony	Line	DPL	$0.8	$0.3	$0.0	$0.5	($0.1)	($0.0)	($0.0)	($0.1)	$0.4	28	7
16	Red Lion At20	Transformer	DPL	$0.4	$0.1	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	45	6
17	North Seaford - Pine Street	Line	DPL	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	111	0
18	Edgemoor At20	Transformer	DPL	$0.9	$0.4	$0.0	$0.5	($0.4)	$0.4	($0.1)	($0.9)	($0.4)	36	43
21	Darley Road - Naamans	Line	DPL	$0.4	$0.2	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	23	0
27	Longwood - Wye Mills	Line	DPL	$0.2	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	52	3

JCPL Control Zone

Table 7-25 JCPL Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 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	$9.8	$3.7	$0.0	$6.1	$0.3	($0.3)	($0.1)	$0.6	$6.6	1,050	367
2	Branchburg - Readington	Line	PSEG	$2.7	($0.4)	$0.1	$3.1	($0.4)	$0.0	$0.1	($0.3)	$2.8	712	158
3	Athenia - Saddlebrook	Line	PSEG	($3.1)	($1.0)	($0.0)	($2.1)	($0.2)	$0.1	$0.0	($0.2)	($2.3)	2,591	321
4	Redoak - Sayreville	Line	JCPL	($0.8)	($2.3)	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	443	13
5	Graceton - Raphael Road	Line	BGE	($2.3)	($1.2)	($0.0)	($1.1)	$0.2	$0.1	$0.0	$0.1	($0.9)	197	99
6	East Frankfort - Crete	Line	ComEd	$1.5	$0.6	($0.0)	$0.9	$0.0	($0.0)	$0.0	$0.1	$0.9	1,650	600
7	Bedington - Black Oak	Interface	500	$1.0	$0.5	$0.0	$0.5	($0.0)	($0.0)	$0.0	($0.0)	$0.5	1,328	43
8	West	Interface	500	$0.7	$0.3	$0.0	$0.4	$0.0	($0.1)	($0.0)	$0.1	$0.5	82	41
9	Doubs	Transformer	AP	$0.9	$0.6	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.2	$0.5	536	283
10	Cloverdale - Lexington	Line	AEP	$0.6	$0.2	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.1	$0.5	578	341
11	Tiltonsville - Windsor	Line	AP	$0.9	$0.5	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.5	1,127	270
12	Atlantic - Larrabee	Line	JCPL	$0.3	($0.1)	$0.0	$0.4	$0.0	($0.1)	($0.0)	$0.1	$0.4	96	12
13	Sammis - Wylie Ridge	Line	AP	$0.6	$0.2	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	494	44
14	Brandon Shores - Riverside	Line	BGE	$0.5	$0.3	$0.0	$0.3	$0.1	($0.0)	($0.0)	$0.0	$0.3	73	55
15	East	Interface	500	$0.6	$0.3	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	75	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	4
17	Franklin - West Wharton	Line	JCPL	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	37	0
20	Kilmer - Sayreville	Line	JCPL	$0.5	$0.3	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	117	0
159	Greystone - West Wharton	Line	JCPL	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	4	0

Table 7-26 JCPL Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	West	Interface	500	$9.7	$3.9	$0.0	$5.7	$0.0	($0.1)	($0.0)	$0.1	$5.8	391	55
2	5004/5005 Interface	Interface	500	$4.8	$1.9	$0.0	$2.9	$0.1	($0.9)	($0.0)	$0.9	$3.8	334	198
3	Kammer	Transformer	500	$4.5	$1.7	$0.0	$2.8	($0.0)	($0.4)	($0.0)	$0.3	$3.2	1,554	726
4	Wylie Ridge	Transformer	AP	$3.9	$1.4	$0.0	$2.5	$0.1	($0.6)	($0.0)	$0.7	$3.2	354	335
5	Atlantic - Larrabee	Line	JCPL	$1.8	$0.4	$0.0	$1.5	($0.6)	($0.5)	($0.0)	($0.1)	$1.3	188	45
6	Athenia - Saddlebrook	Line	PSEG	($1.3)	($0.3)	($0.0)	($1.0)	($0.0)	$0.1	$0.0	($0.1)	($1.1)	979	128
7	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.9	$0.8	($0.1)	$1.0	($0.0)	($0.1)	$0.0	$0.1	$1.1	1,713	671
8	Sammis - Wylie Ridge	Line	AP	$1.4	$0.5	$0.0	$0.9	$0.0	$0.0	($0.0)	$0.0	$0.9	622	101
9	East Frankfort - Crete	Line	ComEd	$1.2	$0.5	($0.0)	$0.7	($0.0)	($0.0)	$0.0	$0.0	$0.7	1,333	161
10	Cloverdale - Lexington	Line	AEP	$0.8	$0.3	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.6	666	239
11	Graceton - Raphael Road	Line	BGE	($1.3)	($0.7)	($0.0)	($0.6)	$0.2	$0.2	$0.0	$0.1	($0.5)	174	90
12	Buckingham - Pleasant Valley	Line	PECO	$0.7	$0.2	$0.0	$0.4	($0.1)	($0.1)	($0.0)	$0.0	$0.5	131	59
13	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.7	$0.3	$0.0	$0.4	$0.0	$0.0	($0.0)	$0.0	$0.4	539	132
14	Tiltonsville - Windsor	Line	AP	$0.9	$0.5	$0.0	$0.4	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	794	198
15	Leonia - New Milford	Line	PSEG	($0.5)	($0.1)	($0.0)	($0.3)	($0.0)	$0.0	$0.0	($0.0)	($0.4)	2,164	30
38	Redoak - Sayreville	Line	JCPL	($0.0)	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.0	30	5
46	Deep Run - Englishtown	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2
48	Kilmer - Sayreville	Line	JCPL	$0.4	$0.2	$0.0	$0.2	($0.0)	$0.2	$0.0	($0.2)	$0.0	0	11
49	Franklin - West Wharton	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	29	0
61	Atlantic - New Prospect Road	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0

Met-Ed Control Zone

Table 7-27 Met-Ed Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 SOM, Table 7-27)

				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	117	26
2	5004/5005 Interface	Interface	500	$6.6	$5.6	($0.0)	$1.0	($0.1)	($0.5)	($0.0)	$0.3	$1.3	1,050	367
3	AP South	Interface	500	$3.0	$2.1	$0.0	$0.9	($0.0)	($0.1)	($0.1)	($0.1)	$0.8	2,090	1,010
4	Graceton - Raphael Road	Line	BGE	($1.6)	($2.2)	($0.0)	$0.6	$0.1	$0.2	$0.1	($0.0)	$0.6	197	99
5	Middletown Jct	Transformer	Met-Ed	$0.6	($0.1)	$0.0	$0.7	($0.1)	$0.0	$0.0	($0.1)	$0.6	11	4
6	Collins - Middletown Jct	Line	Met-Ed	$0.2	($0.2)	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	119	20
7	Branchburg - Readington	Line	PSEG	($0.3)	($0.6)	($0.0)	$0.2	$0.0	$0.0	$0.1	$0.1	$0.3	712	158
8	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.1	($0.2)	$0.0	$0.3	$0.3	0	27
9	West	Interface	500	$0.5	$0.3	$0.0	$0.2	($0.0)	($0.1)	($0.0)	$0.1	$0.3	82	41
10	Bedington - Black Oak	Interface	500	$1.9	$1.8	$0.1	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	1,328	43
11	Athenia - Saddlebrook	Line	PSEG	($0.9)	($0.8)	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.1)	($0.2)	2,591	321
12	Tiltonsville - Windsor	Line	AP	$0.6	$0.8	$0.0	($0.2)	($0.0)	($0.0)	($0.0)	$0.0	($0.2)	1,127	270
13	Doubs - Pleasant View	Line	AP	($0.1)	($0.1)	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	24	20
14	Fort Martin - Ronco	Line	AP	$0.1	$0.2	$0.0	($0.0)	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	31	42
15	Cloverdale - Lexington	Line	AEP	$0.6	$0.7	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.1)	($0.1)	578	341
22	Cly - Collins	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	18	0
37	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	14	0
39	Yorkana A	Transformer	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	0	5
46	Germantown - Straban	Line	Met-Ed	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
67	Cly - Newberry	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

Table 7-28 Met-Ed Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	Brunner Island - Yorkana	Line	Met-Ed	$0.1	($0.3)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	33	16
2	Graceton - Raphael Road	Line	BGE	($1.0)	($1.5)	($0.0)	$0.5	$0.1	$0.2	$0.0	($0.1)	$0.4	174	90
3	AP South	Interface	500	$1.6	$1.3	$0.0	$0.4	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	1,650	282
4	5004/5005 Interface	Interface	500	$3.1	$3.5	$0.0	($0.4)	($0.1)	($0.3)	($0.0)	$0.1	($0.3)	334	198
5	Kammer	Transformer	500	$3.4	$3.9	$0.0	($0.4)	($0.0)	($0.2)	($0.1)	$0.1	($0.3)	1,554	726
6	Wylie Ridge	Transformer	AP	$3.1	$2.8	$0.0	$0.3	($0.1)	($0.2)	($0.0)	$0.0	$0.3	354	335
7	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.3	$1.5	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	$0.0	($0.3)	1,713	671
8	Tiltonsville - Windsor	Line	AP	$0.6	$0.9	$0.0	($0.3)	$0.0	($0.1)	($0.0)	$0.0	($0.2)	794	198
9	East Frankfort - Crete	Line	ComEd	$0.8	$0.9	$0.0	($0.2)	$0.0	($0.0)	($0.0)	($0.0)	($0.2)	1,333	161
10	Middletown Jct	Transformer	Met-Ed	$0.2	($0.0)	$0.0	$0.3	($0.1)	$0.0	($0.0)	($0.1)	$0.2	59	12
11	West	Interface	500	$6.9	$6.8	$0.0	$0.1	($0.0)	($0.1)	($0.0)	$0.0	$0.2	391	55
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.4	$0.6	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.1)	539	132
13	Sammis - Wylie Ridge	Line	AP	$1.0	$1.2	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.1)	622	101
14	Cloverdale - Lexington	Line	AEP	$0.7	$0.8	$0.0	($0.1)	($0.0)	($0.0)	($0.0)	$0.0	($0.1)	666	239
15	Bedington	Transformer	AP	$0.1	($0.0)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.1	247	103
24	Collins - Middletown Jct	Line	Met-Ed	$0.1	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.1)	$0.0	86	16
26	Ironwood - South Lebanon	Line	Met-Ed	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	18	0
30	Cly - Newberry	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
100	Germantown	Transformer	Met-Ed	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	10	0
116	Gardners - Texas East	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	1

PECO Control Zone

Table 7-29 PECO Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 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	Limerick	Transformer	PECO	$3.1	$0.7	$0.0	$2.4	$0.1	($3.8)	($0.0)	$3.8	$6.3	53	18
2	5004/5005 Interface	Interface	500	$7.5	$12.7	$0.0	($5.2)	($0.0)	$0.2	($0.0)	($0.2)	($5.5)	1,050	367
3	AP South	Interface	500	$1.7	$5.0	$0.0	($3.3)	($0.1)	$0.1	($0.0)	($0.2)	($3.5)	2,090	1,010
4	Bedington - Black Oak	Interface	500	$1.7	$3.2	$0.0	($1.5)	$0.0	$0.0	($0.0)	($0.0)	($1.6)	1,328	43
5	Graceton - Raphael Road	Line	BGE	($1.5)	($2.9)	($0.0)	$1.4	$0.2	$0.4	$0.0	($0.2)	$1.2	197	99
6	Eddystone - Island Road	Line	PECO	$0.4	($0.6)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	31	0
7	Doubs	Transformer	AP	$1.0	$2.0	$0.0	($1.0)	($0.2)	($0.2)	($0.0)	($0.0)	($1.0)	536	283
8	Plymouth Meeting - Whitpain	Line	PECO	$1.1	$0.2	$0.0	$0.9	($0.0)	($0.0)	$0.0	$0.0	$0.9	36	1
9	East Frankfort - Crete	Line	ComEd	$1.4	$2.2	($0.0)	($0.8)	($0.0)	($0.1)	($0.0)	$0.0	($0.8)	1,650	600
10	East	Interface	500	$0.9	$0.3	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	75	0
11	West	Interface	500	$0.5	$1.2	$0.0	($0.6)	($0.0)	($0.1)	$0.0	$0.1	($0.5)	82	41
12	Reid - Ringgold	Line	AP	$0.2	$0.7	$0.0	($0.5)	($0.0)	$0.0	($0.0)	($0.0)	($0.5)	270	15
13	Tiltonsville - Windsor	Line	AP	$0.6	$1.1	$0.0	($0.6)	($0.0)	($0.1)	($0.0)	$0.1	($0.4)	1,127	270
14	Sammis - Wylie Ridge	Line	AP	$0.6	$0.9	$0.0	($0.4)	($0.0)	($0.0)	$0.0	($0.0)	($0.4)	494	44
15	Athenia - Saddlebrook	Line	PSEG	($0.6)	($1.2)	($0.0)	$0.6	$0.0	$0.3	$0.0	($0.3)	$0.3	2,591	321
24	Burlington - Croydon	Line	PECO	($0.1)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	($0.0)	$0.2	737	13
58	Cromby	Transformer	PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	34	22
71	Peachbottom	Transformer	PECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	3
78	Whitpain	Transformer	PECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0
91	Cromby - Perkiomen	Line	PECO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	1

Table 7-30 PECO Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	Kammer	Transformer	500	$1.4	$4.9	$0.0	($3.6)	($0.2)	$0.1	$0.0	($0.2)	($3.8)	1,554	726
2	West	Interface	500	$3.0	$6.2	$0.0	($3.1)	($0.0)	($0.0)	($0.0)	($0.0)	($3.1)	391	55
3	AP South	Interface	500	$0.4	$2.4	$0.0	($2.0)	($0.0)	$0.0	$0.0	($0.0)	($2.1)	1,650	282
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.8	$2.2	($0.0)	($1.4)	($0.0)	$0.0	($0.0)	($0.1)	($1.5)	1,713	671
5	Graceton - Raphael Road	Line	BGE	($0.6)	($2.0)	($0.0)	$1.4	$0.3	$0.4	($0.0)	($0.1)	$1.2	174	90
6	5004/5005 Interface	Interface	500	$2.0	$3.1	$0.0	($1.2)	$0.0	$0.0	$0.0	($0.0)	($1.2)	334	198
7	Wylie Ridge	Transformer	AP	$1.3	$2.3	$0.0	($0.9)	($0.1)	$0.0	($0.1)	($0.1)	($1.1)	354	335
8	East Frankfort - Crete	Line	ComEd	$0.4	$1.2	($0.0)	($0.8)	($0.0)	$0.0	($0.0)	($0.0)	($0.8)	1,333	161
9	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.2	$0.9	($0.0)	($0.7)	($0.0)	$0.0	($0.0)	($0.1)	($0.8)	539	132
10	Sammis - Wylie Ridge	Line	AP	$0.5	$1.1	$0.0	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.7)	622	101
11	Tiltonsville - Windsor	Line	AP	$0.3	$1.0	$0.0	($0.7)	($0.0)	($0.0)	$0.0	$0.0	($0.7)	794	198
12	Cloverdale - Lexington	Line	AEP	$0.3	$1.0	$0.0	($0.6)	($0.0)	($0.0)	($0.0)	$0.0	($0.6)	666	239
13	Mount Storm - Pruntytown	Line	AP	$0.1	$0.5	$0.0	($0.5)	$0.0	$0.0	$0.0	($0.0)	($0.5)	523	25
14	Conastone	Transformer	BGE	($0.0)	($0.3)	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	17	1
15	Krendale - Seneca	Line	AP	$0.2	$0.5	$0.0	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	225	0
16	Holmesburg - Richmond	Line	PECO	($0.1)	($0.2)	($0.0)	$0.1	($0.0)	($0.1)	$0.0	$0.1	$0.2	193	6
19	Eddystone - Scott Paper	Line	PECO	$0.2	($0.0)	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	30	2
24	Burlington - Croydon	Line	PECO	($0.1)	($0.3)	($0.0)	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	1,531	3
27	Buckingham - Pleasant Valley	Line	PECO	($0.4)	($0.4)	($0.0)	($0.0)	($0.0)	$0.1	$0.0	($0.1)	($0.1)	131	59
34	Limerick	Transformer	PECO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	21	0

PENELEC Control Zone

Table 7-31 PENELEC Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 SOM, Table 7-31)

				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	($31.6)	($47.7)	($0.0)	$16.1	$5.9	$1.6	$0.0	$4.4	$20.5	2,090	1,010
2	5004/5005 Interface	Interface	500	($7.1)	($22.7)	($0.1)	$15.5	$1.4	$0.6	$0.1	$0.9	$16.4	1,050	367
3	Bedington - Black Oak	Interface	500	($11.7)	($17.8)	($0.0)	$6.1	$0.4	$0.0	$0.0	$0.4	$6.4	1,328	43
4	Seward	Transformer	PENELEC	$10.2	$6.2	$0.0	$4.0	($0.1)	$0.0	($0.0)	($0.1)	$3.9	344	43
5	AEP-DOM	Interface	500	($4.4)	($6.3)	($0.0)	$1.8	$0.2	($0.1)	$0.0	$0.3	$2.1	471	84
6	East Frankfort - Crete	Line	ComEd	$3.3	$4.2	$0.0	($0.9)	($0.6)	$0.1	($0.0)	($0.6)	($1.5)	1,650	600
7	Mount Storm - Pruntytown	Line	AP	($0.6)	($1.0)	($0.0)	$0.4	$1.7	$0.6	$0.0	$1.0	$1.4	87	244
8	Sammis - Wylie Ridge	Line	AP	$0.5	$1.8	$0.0	($1.3)	($0.1)	($0.1)	($0.0)	($0.0)	($1.3)	494	44
9	Tiltonsville - Windsor	Line	AP	$1.9	$2.5	$0.0	($0.6)	($0.4)	$0.1	($0.0)	($0.5)	($1.1)	1,127	270
10	Homer City - Seward	Line	PENELEC	$3.3	$2.3	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	59	0
11	Pleasant View	Transformer	Dominion	($0.0)	($0.1)	($0.0)	$0.0	$0.6	($0.3)	$0.0	$0.9	$0.9	31	101
12	Hunterstown	Transformer	Met-Ed	($0.6)	($1.5)	($0.0)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	117	26
13	Graceton - Raphael Road	Line	BGE	($1.5)	($2.2)	$0.0	$0.7	$0.2	$0.1	($0.0)	$0.2	$0.8	197	99
14	West	Interface	500	($0.3)	($1.1)	$0.0	$0.8	$0.2	$0.2	$0.0	$0.0	$0.8	82	41
15	Doubs	Transformer	AP	($1.7)	($2.3)	$0.0	$0.6	$0.2	($0.0)	($0.0)	$0.2	$0.8	536	283
21	Altoona - Bear Rock	Line	PENELEC	($0.5)	($0.9)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	16	0
24	Homer City	Transformer	PENELEC	$0.7	$0.4	($0.0)	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	81	1
25	Homer City - Johnstown	Line	PENELEC	$0.9	$0.6	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	32	0
28	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.2	$0.5	$0.0	($0.3)	($0.3)	0	27
42	Garrett	Transformer	PENELEC	$1.0	$0.8	$0.0	$0.2	$0.0	$0.1	$0.0	($0.0)	$0.2	102	3

Table 7-32 PENELEC Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	West	Interface	500	($2.2)	($15.2)	($0.0)	$13.0	$0.1	$0.1	$0.0	($0.1)	$13.0	391	55
2	AP South	Interface	500	($9.9)	($20.7)	($0.0)	$10.8	$0.8	$0.3	$0.1	$0.5	$11.3	1,650	282
3	Wylie Ridge	Transformer	AP	$1.5	$10.3	$0.1	($8.8)	($0.6)	($0.7)	($0.0)	$0.1	($8.7)	354	335
4	5004/5005 Interface	Interface	500	($1.6)	($9.2)	($0.0)	$7.6	$0.4	$1.5	$0.0	($1.1)	$6.5	334	198
5	Kammer	Transformer	500	$2.8	$9.0	$0.2	($6.0)	($0.2)	($0.7)	($0.1)	$0.4	($5.6)	1,554	726
6	Sammis - Wylie Ridge	Line	AP	$1.0	$3.7	$0.1	($2.7)	($0.1)	($0.1)	$0.0	($0.0)	($2.7)	622	101
7	Mount Storm - Pruntytown	Line	AP	($2.4)	($4.6)	($0.0)	$2.2	$0.3	$0.1	$0.0	$0.3	$2.5	523	25
8	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.6	$5.1	($0.0)	($2.5)	$0.2	($0.5)	($0.0)	$0.6	($1.8)	1,713	671
9	Seward	Transformer	PENELEC	$3.2	$1.8	($0.0)	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	57	0
10	Tiltonsville - Windsor	Line	AP	$0.7	$2.1	$0.0	($1.4)	$0.1	$0.0	($0.0)	$0.0	($1.4)	794	198
11	Homer City - Seward	Line	PENELEC	$2.8	$1.5	($0.0)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	58	0
12	East Frankfort - Crete	Line	ComEd	$1.5	$2.7	$0.0	($1.2)	$0.0	($0.0)	($0.0)	$0.0	($1.2)	1,333	161
13	Krendale - Seneca	Line	AP	$0.5	$1.4	$0.0	($0.9)	$0.0	$0.0	$0.0	$0.0	($0.9)	225	0
14	Homer City	Transformer	PENELEC	$0.9	$0.1	($0.0)	$0.8	($0.0)	$0.0	$0.0	($0.0)	$0.8	145	2
15	Homer City - Shelocta	Line	PENELEC	($1.7)	($2.5)	($0.0)	$0.8	($0.1)	$0.1	$0.0	($0.1)	$0.7	200	55
18	Altoona - Bear Rock	Line	PENELEC	($0.6)	($1.1)	($0.0)	$0.5	$0.0	($0.0)	$0.0	$0.0	$0.5	37	4
24	Altoona - Raystown	Line	PENELEC	($0.8)	($1.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	50	0
25	Keystone - Shelocta	Line	PENELEC	($0.5)	($0.8)	($0.0)	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.3	78	8
27	Clarks Summit - Eclipse	Line	PENELEC	$0.1	($0.1)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	16	2
29	Blairsville East	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	0	25

Pepco Control Zone

Table 7-33 Pepco Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 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	AP South	Interface	500	$69.5	$51.5	$1.4	$19.3	($4.2)	($3.1)	($1.4)	($2.5)	$16.8	2,090	1,010
2	Bedington - Black Oak	Interface	500	$28.5	$19.9	$0.6	$9.3	($0.5)	($0.6)	($0.3)	($0.1)	$9.2	1,328	43
3	Reid - Ringgold	Line	AP	$4.6	$2.8	$0.1	$2.0	($0.0)	($0.0)	($0.0)	($0.0)	$2.0	270	15
4	Doubs	Transformer	AP	$18.7	$12.1	$0.5	$7.1	($3.1)	$0.6	($1.5)	($5.2)	$1.9	536	283
5	Graceton - Raphael Road	Line	BGE	$5.3	$3.6	$0.2	$1.9	($0.6)	($0.4)	($0.2)	($0.3)	$1.6	197	99
6	AEP-DOM	Interface	500	$8.0	$6.6	$0.1	$1.5	($0.1)	($0.2)	($0.1)	($0.0)	$1.5	471	84
7	5004/5005 Interface	Interface	500	$4.7	$3.2	$0.2	$1.7	($0.2)	($0.1)	($0.1)	($0.2)	$1.5	1,050	367
8	Bowie	Line	Pepco	$2.3	$1.1	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	44	0
9	East Frankfort - Crete	Line	ComEd	$3.6	$2.2	$0.0	$1.5	($0.3)	($0.1)	($0.0)	($0.2)	$1.2	1,650	600
10	Bowie - Lanham	Line	Pepco	$2.2	$0.9	$0.1	$1.4	($0.3)	($0.2)	($0.1)	($0.2)	$1.1	36	13
11	Cloverdale - Lexington	Line	AEP	$4.8	$3.3	$0.1	$1.5	($1.0)	($0.8)	($0.2)	($0.4)	$1.1	578	341
12	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	($0.0)	$0.6	$0.2	$0.4	$0.8	$0.8	31	101
13	Danville - East Danville	Line	Dominion	$3.1	$2.1	($0.1)	$0.9	($0.2)	($0.1)	$0.1	($0.1)	$0.8	879	85
14	Nipetown - Reid	Line	AP	$2.1	$1.4	$0.1	$0.8	($0.1)	($0.1)	($0.0)	($0.0)	$0.8	211	49
15	Tiltonsville - Windsor	Line	AP	$2.2	$1.3	$0.0	$0.9	($0.2)	($0.1)	($0.1)	($0.2)	$0.7	1,127	270
16	Benning - Ritchie	Line	Pepco	$0.8	$0.2	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	78	0
19	Buzzard - Ritchie	Line	Pepco	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	58	1
22	Bowie	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.2	$0.4	($0.1)	($0.3)	($0.3)	0	9
29	Burtonsville - Metzerott Rd.	Line	Pepco	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	17	0
89	Pumphrey	Transformer	Pepco	($0.1)	($0.1)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	11	0

Table 7-34 Pepco Control Z one top congestion cost impacts (By facility): January through June 2009 (See 2009 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	$32.9	$25.1	$0.5	$8.3	($0.9)	($2.2)	($0.5)	$0.9	$9.1	1,650	282
2	Kammer	Transformer	500	$11.8	$8.5	$0.2	$3.5	($0.6)	($1.4)	($0.2)	$0.6	$4.1	1,554	726
3	Mount Storm - Pruntytown	Line	AP	$7.5	$5.8	$0.1	$1.9	($0.0)	($0.5)	($0.0)	$0.5	$2.3	523	25
4	West	Interface	500	$8.1	$6.0	$0.0	$2.1	($0.0)	($0.1)	($0.0)	$0.0	$2.2	391	55
5	Wylie Ridge	Transformer	AP	$6.2	$4.9	$0.0	$1.3	($0.3)	($0.7)	($0.0)	$0.3	$1.7	354	335
6	Cloverdale - Lexington	Line	AEP	$5.0	$3.7	$0.1	$1.4	($0.1)	($0.3)	($0.1)	$0.1	$1.5	666	239
7	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.9	$2.7	($0.0)	$1.2	($0.1)	($0.4)	($0.0)	$0.3	$1.5	1,713	671
8	Graceton - Raphael Road	Line	BGE	$3.1	$2.1	$0.1	$1.0	($0.4)	($0.5)	($0.1)	($0.0)	$1.0	174	90
9	Sammis - Wylie Ridge	Line	AP	$2.4	$1.7	$0.0	$0.8	($0.1)	($0.1)	($0.0)	($0.0)	$0.8	622	101
10	East Frankfort - Crete	Line	ComEd	$2.2	$1.5	$0.0	$0.7	$0.0	($0.1)	($0.0)	$0.1	$0.7	1,333	161
11	Mount Storm	Transformer	AP	$1.7	$1.3	$0.0	$0.5	($0.0)	($0.3)	($0.0)	$0.2	$0.7	123	46
12	Bedington - Black Oak	Interface	500	$1.8	$1.3	$0.0	$0.5	($0.0)	($0.1)	($0.0)	$0.1	$0.6	74	61
13	Buzzard - Ritchie	Line	Pepco	$0.2	$0.0	$0.0	$0.2	($0.2)	$0.0	($0.1)	($0.4)	($0.2)	27	16
14	Tiltonsville - Windsor	Line	AP	$1.4	$0.9	$0.1	$0.5	($0.0)	($0.1)	($0.1)	($0.0)	$0.5	794	198
15	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.3	$1.0	$0.0	$0.3	$0.0	($0.2)	$0.0	$0.2	$0.5	539	132
17	Brighton	Transformer	Pepco	$0.7	$0.4	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	43	1
18	Dickerson - Pleasant View	Line	Pepco	$0.7	$0.5	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	38	13
32	Pumphrey - Westport	Line	Pepco	($0.3)	($0.2)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	573	0
66	Brighton - Mt. Zion	Line	Pepco	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0
188	Burches Hill	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	1

PPL Control Zone

Table 7-35 PPL Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 SOM, Table 7-35)

				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)	1,050	367
2	AP South	Interface	500	$1.6	$1.1	$0.3	$0.8	$0.2	($0.1)	($0.0)	$0.2	$1.1	2,090	1,010
3	Graceton - Raphael Road	Line	BGE	($3.4)	($4.5)	($0.1)	$1.0	$0.0	$0.0	$0.0	($0.0)	$1.0	197	99
4	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.7	$0.2	$0.4	$0.9	$0.9	0	27
5	East Frankfort - Crete	Line	ComEd	$2.6	$3.5	$0.0	($0.9)	$0.2	($0.0)	$0.0	$0.2	($0.7)	1,650	600
6	Susquehanna	Transformer	PPL	$1.0	$0.3	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	36	0
7	Harwood - Susquehanna	Line	PPL	$0.2	($0.7)	$0.0	$0.9	$0.3	$0.5	($0.1)	($0.3)	$0.6	25	22
8	Sammis - Wylie Ridge	Line	AP	$1.2	$1.6	$0.0	($0.4)	($0.0)	$0.0	($0.0)	($0.0)	($0.4)	494	44
9	Bedington - Black Oak	Interface	500	$1.6	$1.4	$0.1	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.4	1,328	43
10	Tiltonsville - Windsor	Line	AP	$1.4	$1.8	$0.0	($0.4)	$0.1	$0.0	$0.0	$0.1	($0.3)	1,127	270
11	West	Interface	500	$1.3	$1.5	$0.0	($0.2)	$0.0	$0.1	($0.0)	($0.1)	($0.3)	82	41
12	Martins Creek - Siegfried	Line	PPL	($0.0)	($0.1)	$0.0	$0.0	($0.0)	$0.2	($0.1)	($0.3)	($0.3)	7	17
13	Cloverdale - Lexington	Line	AEP	$1.1	$1.6	$0.1	($0.5)	$0.2	$0.0	$0.0	$0.2	($0.2)	578	341
14	Pleasant View	Transformer	Dominion	($0.0)	($0.1)	($0.0)	$0.0	($0.1)	$0.1	$0.0	($0.2)	($0.2)	31	101
15	Limerick	Transformer	PECO	($0.2)	($0.4)	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	53	18
19	Alburtis - Hosensack	Line	PPL	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	($0.0)	($0.1)	($0.1)	0	25
38	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	5
50	Harwood	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
61	Facerock	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.0	$0.0	$0.0	0	6
71	East Palmerton - Siegfried	Line	PPL	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0

Table 7-36 PPL Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	Kammer	Transformer	500	$0.8	$2.3	$0.4	($1.1)	($0.1)	($0.2)	($0.1)	($0.1)	($1.1)	1,554	726
2	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.3	$1.4	($0.1)	($1.1)	($0.2)	($0.1)	$0.0	$0.0	($1.1)	1,713	671
3	AP South	Interface	500	$0.4	($0.2)	$0.2	$0.7	$0.0	($0.0)	$0.1	$0.1	$0.9	1,650	282
4	West	Interface	500	$2.8	$4.1	$0.5	($0.8)	($0.0)	($0.1)	($0.0)	$0.1	($0.7)	391	55
5	Graceton - Raphael Road	Line	BGE	($0.3)	($0.9)	($0.0)	$0.6	$0.1	$0.0	$0.0	$0.1	$0.6	174	90
6	Harwood - Susquehanna	Line	PPL	$0.1	($0.4)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	13	0
7	Sammis - Wylie Ridge	Line	AP	$0.1	$0.7	$0.1	($0.5)	$0.0	($0.0)	$0.0	$0.1	($0.4)	622	101
8	Brunner Island - Yorkana	Line	Met-Ed	($0.0)	($0.4)	($0.0)	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	33	16
9	Wylie Ridge	Transformer	AP	$1.1	$1.8	$0.3	($0.4)	$0.2	$0.1	$0.0	$0.1	($0.3)	354	335
10	PL North	Interface	PPL	$0.0	$0.0	$0.0	$0.0	$0.4	$0.6	($0.0)	($0.3)	($0.3)	0	176
11	Mount Storm - Pruntytown	Line	AP	$0.1	($0.1)	$0.0	$0.3	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	523	25
12	Atlantic - Larrabee	Line	JCPL	$0.0	$0.1	$0.0	($0.1)	($0.1)	$0.1	$0.0	($0.2)	($0.3)	188	45
13	East Frankfort - Crete	Line	ComEd	$0.2	$0.5	$0.0	($0.3)	($0.0)	($0.0)	$0.0	$0.0	($0.2)	1,333	161
14	5004/5005 Interface	Interface	500	$1.4	$2.4	$0.3	($0.6)	$0.1	($0.8)	($0.1)	$0.8	$0.2	334	198
15	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.2	$0.4	($0.0)	($0.2)	($0.1)	($0.1)	$0.0	($0.0)	($0.2)	539	132
28	Dauphin - Juniata	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0
132	Berwick - Koonsville	Line	PPL	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	57	0
180	Frackville - Siegfried	Line	PPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	4
318	Peach Tap	Transformer	PPL	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

PSEG Control Zone

Table 7-37 PSEG Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 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	Branchburg - Readington	Line	PSEG	$5.1	$0.8	$0.4	$4.7	($0.1)	$0.6	($0.5)	($1.2)	$3.5	712	158
2	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.7)	$1.1	($1.7)	($3.4)	($3.4)	454	38
3	Athenia - Saddlebrook	Line	PSEG	$12.2	$2.4	$7.2	$17.1	($6.9)	$2.6	($4.9)	($14.3)	$2.7	2,591	321
4	AP South	Interface	500	$0.4	$3.5	$1.7	($1.5)	$0.2	($0.3)	($1.2)	($0.8)	($2.3)	2,090	1,010
5	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.1)	$0.4	($0.9)	($1.4)	($1.6)	209	35
6	Bedington - Black Oak	Interface	500	$1.2	$2.6	$0.7	($0.7)	($0.0)	($0.0)	($0.1)	($0.1)	($0.8)	1,328	43
7	Graceton - Raphael Road	Line	BGE	($3.2)	($3.4)	($0.2)	($0.0)	$0.3	($0.2)	$0.3	$0.8	$0.8	197	99
8	Doubs	Transformer	AP	$1.3	$1.1	$0.2	$0.4	($0.3)	$0.3	($0.5)	($1.1)	($0.7)	536	283
9	5004/5005 Interface	Interface	500	$13.5	$13.9	$1.4	$1.0	($0.0)	$0.9	($0.7)	($1.7)	($0.7)	1,050	367
10	Pleasant View	Transformer	Dominion	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	($0.1)	$0.2	$0.7	$0.7	31	101
11	Bayway - Federal Square	Line	PSEG	$0.4	($0.2)	$0.0	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.6	344	1
12	Redoak - Sayreville	Line	JCPL	$0.4	($0.1)	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.0)	$0.6	443	13
13	Bayonne - PVSC	Line	PSEG	$0.0	($0.5)	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	578	0
14	Cloverdale - Lexington	Line	AEP	$0.9	$1.2	$0.1	($0.2)	$0.1	$0.2	($0.2)	($0.4)	($0.5)	578	341
15	Hudson - Marion	Line	PSEG	$0.3	$0.1	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	170	0
16	Leonia - New Milford	Line	PSEG	$0.2	$0.1	$0.4	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	568	1
20	North Ave - Pvsc	Line	PSEG	$0.1	($0.3)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	285	0
22	Fairlawn - Saddlebrook	Line	PSEG	$0.4	$0.3	$0.7	$0.8	($0.0)	$0.1	($0.4)	($0.5)	$0.3	470	17
24	Cedar Grove - Clifton	Line	PSEG	$0.2	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	63	0
29	Linden - North Ave	Line	PSEG	$0.1	($0.1)	$0.0	$0.2	($0.0)	($0.0)	($0.0)	$0.0	$0.2	134	1

Table 7-38 PSEG Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	Plainsboro - Trenton	Line	PSEG	$3.5	($0.1)	$0.1	$3.8	($0.3)	$0.4	($0.1)	($0.7)	$3.1	389	164
2	Leonia - New Milford	Line	PSEG	$1.5	$0.5	$2.3	$3.3	($0.0)	$0.0	($0.3)	($0.3)	$3.0	2,164	30
3	Athenia - Saddlebrook	Line	PSEG	$3.2	$0.5	$1.3	$3.9	($0.3)	$0.1	($0.5)	($0.9)	$3.0	979	128
4	AP South	Interface	500	$0.5	$2.5	$0.7	($1.3)	$0.0	($0.1)	($0.3)	($0.2)	($1.5)	1,650	282
5	Fairlawn - Saddlebrook	Line	PSEG	$1.0	$0.1	$0.5	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	673	0
6	Wylie Ridge	Transformer	AP	$4.3	$5.4	$0.5	($0.6)	$0.0	$0.1	($0.6)	($0.7)	($1.3)	354	335
7	West	Interface	500	$10.9	$12.7	$0.8	($1.0)	($0.0)	$0.0	($0.1)	($0.2)	($1.2)	391	55
8	Cedar Grove - Clifton	Line	PSEG	$1.0	$0.2	$0.4	$1.2	($0.0)	$0.0	($0.0)	($0.1)	$1.1	413	18
9	Hillsdale - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.3	($0.4)	($0.7)	($0.7)	0	42
10	Buckingham - Pleasant Valley	Line	PECO	$0.9	($0.1)	$0.0	$1.0	($0.0)	$0.2	($0.0)	($0.3)	$0.7	131	59
11	5004/5005 Interface	Interface	500	$5.6	$5.4	$0.3	$0.5	$0.0	$0.8	($0.4)	($1.2)	($0.7)	334	198
12	Atlantic - Larrabee	Line	JCPL	$0.3	($0.5)	$0.0	$0.8	$0.0	$0.1	($0.1)	($0.2)	$0.6	188	45
13	Bayway - Federal Square	Line	PSEG	$0.4	($0.2)	$0.0	$0.6	($0.0)	($0.0)	($0.0)	$0.0	$0.6	144	9
14	Brunswick - Edison	Line	PSEG	$1.0	($0.0)	$0.0	$1.1	($0.1)	$0.2	($0.2)	($0.5)	$0.6	138	76
15	Cedar Grove - Roseland	Line	PSEG	$0.4	$0.0	$0.0	$0.4	($0.2)	$0.5	($0.2)	($0.9)	($0.5)	52	70
16	Branchburg - Flagtown	Line	PSEG	$0.6	($0.0)	$0.1	$0.7	($0.0)	$0.1	($0.1)	($0.2)	$0.4	161	16
18	Bayonne - PVSC	Line	PSEG	$0.0	($0.3)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	371	0
20	Athenia - Fairlawn	Line	PSEG	$0.3	$0.0	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.3	106	6
23	Branchburg - Readington	Line	PSEG	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	21	0
24	Sewaren	Transformer	PSEG	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	50	0

RECO Control Zone

Table 7-39 RECO Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 SOM, Table 7-39)

				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	1,050	367
2	Branchburg - Readington	Line	PSEG	$0.3	$0.0	$0.0	$0.3	$0.1	($0.0)	($0.0)	$0.1	$0.4	712	158
3	Athenia - Saddlebrook	Line	PSEG	$0.2	$0.0	($0.0)	$0.1	$0.0	($0.1)	$0.0	$0.1	$0.2	2,591	321
4	AP South	Interface	500	($0.1)	($0.0)	$0.0	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	($0.2)	2,090	1,010
5	Graceton - Raphael Road	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	197	99
6	Hawthorn - Hinchmans Ave	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	209	35
7	Hawthorn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	454	38
8	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	1,650	600
9	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	536	283
10	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	1,127	270
11	West	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	82	41
12	Brandon Shores - Riverside	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	73	55
13	Fairlawn - Saddlebrook	Line	PSEG	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	470	17
14	Cloverdale - Lexington	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	578	341
15	Palisades - Vergennes	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	235	91

Table 7-40 RECO Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	West	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	391	55
2	Kammer	Transformer	500	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	1,554	726
3	5004/5005 Interface	Interface	500	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.1)	$0.2	334	198
4	Wylie Ridge	Transformer	AP	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	354	335
5	Athenia - Saddlebrook	Line	PSEG	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	979	128
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.1	$0.0	($0.0)	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	1,713	671
7	Graceton - Raphael Road	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	174	90
8	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	1,333	161
9	AP South	Interface	500	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	1,650	282
10	Sammis - Wylie Ridge	Line	AP	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	622	101
11	Fairlawn - Saddlebrook	Line	PSEG	($0.0)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	673	0
12	Tiltonsville - Windsor	Line	AP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	794	198
13	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	539	132
14	Krendale - Seneca	Line	AP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	225	0
15	Cloverdale - Lexington	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	666	239

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-41 AEP Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 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	AP South	Interface	500	($20.3)	($53.0)	$0.4	$33.1	($3.4)	$1.6	$0.6	($4.4)	$28.7	2,090	1,010
2	AEP-DOM	Interface	500	$7.5	($20.1)	$1.0	$28.6	($0.2)	($0.3)	($0.3)	($0.1)	$28.4	471	84
3	Bedington - Black Oak	Interface	500	($8.8)	($18.7)	$0.1	$10.0	($0.1)	($0.0)	$0.0	($0.0)	$10.0	1,328	43
4	Baker - Broadford	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($1.5)	$1.0	($3.5)	($5.9)	($5.6)	10	74
5	5004/5005 Interface	Interface	500	($10.3)	($15.7)	($0.2)	$5.2	($0.8)	$1.2	$0.3	($1.7)	$3.5	1,050	367
6	Kanawha River	Transformer	AEP	$2.1	($0.2)	$0.4	$2.7	$0.0	($0.0)	($0.0)	$0.0	$2.7	162	11
7	Kanawha - Kincaid	Line	AEP	$1.4	($0.7)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	220	0
8	Culloden - Wyoming	Line	AEP	$0.6	($0.8)	$0.5	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	46	0
9	Sullivan	Transformer	AEP	($0.0)	($1.4)	($0.0)	$1.3	$0.0	$0.0	$0.0	($0.0)	$1.3	185	47
10	Belmont	Transformer	AP	$0.9	($0.1)	$0.1	$1.0	$0.2	($0.0)	($0.0)	$0.3	$1.3	344	9
11	Mahans Lane - Tidd	Line	AEP	($0.4)	($1.6)	($0.1)	$1.2	$0.1	$0.0	$0.0	$0.1	$1.3	268	120
12	Cloverdale - Lexington	Line	AEP	($4.9)	($4.7)	($0.3)	($0.5)	($0.4)	$0.7	$0.4	($0.7)	($1.2)	578	341
13	East Frankfort - Crete	Line	ComEd	$4.7	$4.1	$1.3	$1.8	$0.2	($0.1)	($1.0)	($0.7)	$1.1	1,650	600
14	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	$0.0	$0.7	$0.7	$0.0	($0.0)	($1.8)	($1.8)	($1.0)	945	80
15	Danville - East Danville	Line	Dominion	($5.5)	($5.5)	($1.0)	($1.1)	$0.2	$0.3	$0.3	$0.1	($1.0)	879	85
17	Kammer - Natrium	Line	AEP	$0.3	($0.4)	$0.0	$0.7	$0.0	($0.0)	($0.0)	$0.1	$0.8	178	19
22	Conesville Prep - Conesville	Line	AEP	($0.0)	($0.4)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	118	0
26	Breed - Wheatland	Line	AEP	$0.0	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	26	0
27	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.1)	($0.0)	($0.3)	($0.3)	0	48
29	Ruth - Turner	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	22	11

Table 7-42 AEP Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	AP South	Interface	500	($13.6)	($22.9)	$0.9	$10.1	($0.6)	$0.1	$0.2	($0.6)	$9.6	1,650	282
2	Ruth - Turner	Line	AEP	$4.6	($1.6)	$0.5	$6.7	($1.2)	($0.4)	($0.1)	($0.9)	$5.8	639	270
3	Kammer	Transformer	500	($11.6)	($18.5)	($0.3)	$6.7	($0.5)	$1.4	$0.6	($1.4)	$5.3	1,554	726
4	Kanawha - Kincaid	Line	AEP	$2.8	($2.1)	$0.2	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	291	0
5	Kammer - Ormet	Line	AEP	$7.8	$1.1	$0.3	$6.9	($1.6)	$0.5	($0.1)	($2.2)	$4.7	552	509
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$12.6	$5.8	$1.0	$7.8	($2.2)	($0.9)	($2.1)	($3.4)	$4.4	1,713	671
7	Kanawha River	Transformer	AEP	$3.2	($0.3)	$0.5	$4.0	$0.1	($0.3)	($0.1)	$0.4	$4.3	159	37
8	Kanawha River - Bradley	Line	AEP	$1.3	($2.2)	$0.2	$3.8	($0.0)	$0.1	$0.0	($0.1)	$3.7	24	15
9	Breed - Wheatland	Line	AEP	$0.1	($3.1)	($0.3)	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	408	0
10	Sammis - Wylie Ridge	Line	AP	($4.3)	($2.3)	($0.1)	($2.1)	($0.2)	$0.1	($0.0)	($0.4)	($2.5)	622	101
11	Mount Storm - Pruntytown	Line	AP	($3.1)	($5.2)	$0.2	$2.3	$0.2	$0.0	$0.0	$0.2	$2.5	523	25
12	East Frankfort - Crete	Line	ComEd	$3.2	$1.9	$1.3	$2.7	($0.0)	$0.1	($0.7)	($0.8)	$1.9	1,333	161
13	Cloverdale - Lexington	Line	AEP	($5.9)	($4.1)	($0.4)	($2.1)	$0.4	$0.2	$0.1	$0.3	($1.8)	666	239
14	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.6	$0.2	$0.2	$0.5	($0.1)	$0.0	($1.8)	($1.9)	($1.4)	62	81
15	AEP-DOM	Interface	500	$0.4	($1.2)	$0.1	$1.7	($0.2)	$0.4	($0.0)	($0.6)	$1.1	101	57
23	Axton	Transformer	AEP	$0.1	($0.4)	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	40	0
25	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.3	($0.1)	$0.1	$0.5	$0.5	0	99
28	Kammer	Transformer	AEP	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.1	($0.0)	($0.1)	$0.3	59	13
29	Marquis - Waverly	Line	AEP	$0.4	$0.0	$0.1	$0.4	($0.0)	$0.0	($0.0)	($0.1)	$0.3	41	9
31	Poston - Postel Tap	Line	AEP	$0.2	($0.3)	$0.1	$0.5	$0.2	$0.3	($0.1)	($0.2)	$0.3	52	54

AP Control Zone

Table 7-43 AP Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 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	($20.3)	($77.3)	($5.6)	$51.4	$3.0	$3.3	$6.0	$5.7	$57.2	2,090	1,010
2	Bedington - Black Oak	Interface	500	($7.4)	($26.6)	($1.0)	$18.3	$0.3	$0.4	$0.1	($0.1)	$18.2	1,328	43
3	Doubs	Transformer	AP	$4.1	($5.8)	($0.3)	$9.6	$1.6	$1.1	$0.4	$0.9	$10.5	536	283
4	AEP-DOM	Interface	500	($2.1)	($7.8)	$0.4	$6.0	$0.3	($0.2)	($0.1)	$0.4	$6.4	471	84
5	5004/5005 Interface	Interface	500	($10.0)	($14.9)	($0.7)	$4.3	$0.6	$1.1	$0.5	$0.0	$4.3	1,050	367
6	Tiltonsville - Windsor	Line	AP	$5.8	$1.4	$0.5	$4.9	($0.9)	($0.2)	($0.7)	($1.4)	$3.5	1,127	270
7	Mount Storm - Pruntytown	Line	AP	($0.3)	($1.6)	($0.0)	$1.3	$1.1	($0.4)	$0.5	$2.0	$3.2	87	244
8	Belmont	Transformer	AP	$2.1	($0.5)	$0.1	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	344	9
9	Fort Martin - Ronco	Line	AP	$0.2	$0.2	$0.1	$0.2	($0.2)	$0.9	($1.4)	($2.5)	($2.3)	31	42
10	Nipetown - Reid	Line	AP	($0.1)	($1.7)	$0.0	$1.6	$0.1	$0.2	($0.0)	($0.1)	$1.6	211	49
11	Halfway - Marlowe	Line	AP	$0.6	($0.7)	($0.0)	$1.3	$0.1	($0.1)	$0.0	$0.2	$1.5	60	18
12	Endless Caverns	Transformer	Dominion	$1.3	$0.0	$0.2	$1.6	$0.0	$0.0	($0.0)	($0.0)	$1.5	283	3
13	Middlebourne - Willow	Line	AP	$1.3	($0.2)	$0.2	$1.7	($0.2)	($0.0)	($0.2)	($0.4)	$1.4	220	73
14	Yukon	Transformer	AP	$1.2	$0.1	$0.1	$1.2	$0.0	$0.1	$0.1	($0.0)	$1.2	80	13
15	Albright - Snowy Creek	Line	AP	$0.9	($0.3)	$0.0	$1.2	$0.0	($0.0)	($0.0)	$0.0	$1.2	249	2
17	Bedington - Shepherdstown	Line	AP	$0.2	($0.4)	$0.2	$0.8	$0.0	$0.0	$0.0	$0.0	$0.9	217	10
19	Smith - Wylie Ridge	Line	AP	$0.8	$0.1	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	103	2
20	Hamilton - Weirton	Line	AP	$1.4	$0.5	$0.1	$1.1	($0.1)	$0.1	($0.1)	($0.3)	$0.8	176	17
21	Messic Road - Morgan	Line	AP	($0.8)	($1.6)	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	338	0
23	Kingwood - Pruntytown	Line	AP	$0.7	($0.0)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	147	9

Table 7-44 AP Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	($9.8)	($41.2)	($3.2)	$28.1	$1.5	$1.2	$2.5	$2.8	$31.0	1,650	282
2	Mount Storm - Pruntytown	Line	AP	($2.0)	($10.1)	($0.6)	$7.4	$0.4	$0.2	$0.4	$0.7	$8.1	523	25
3	Kammer	Transformer	500	$10.4	$15.3	$4.8	($0.2)	($1.3)	($1.7)	($5.4)	($5.0)	($5.2)	1,554	726
4	Wylie Ridge	Transformer	AP	$6.1	$7.4	$5.4	$4.1	($1.1)	($0.5)	($7.2)	($7.7)	($3.6)	354	335
5	5004/5005 Interface	Interface	500	($4.9)	($7.1)	($0.6)	$1.7	$0.8	$0.7	$1.6	$1.7	$3.4	334	198
6	Tiltonsville - Windsor	Line	AP	$5.1	$1.7	$0.3	$3.8	($0.5)	($0.2)	($0.8)	($1.0)	$2.8	794	198
7	Bedington - Harmony	Line	AP	$1.8	($0.1)	$0.4	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	199	0
8	Cloverdale - Lexington	Line	AEP	$1.1	($1.3)	$0.8	$3.2	($0.1)	$0.0	($0.8)	($1.0)	$2.2	666	239
9	Carroll - Catoctin	Line	AP	$0.4	$0.0	($0.0)	$0.3	$0.7	($0.8)	$0.2	$1.6	$2.0	99	22
10	Yukon	Transformer	AP	$2.1	$0.4	$0.0	$1.7	$0.0	$0.2	$0.1	($0.1)	$1.6	123	36
11	Bedington - Black Oak	Interface	500	($0.4)	($2.1)	($0.1)	$1.7	($0.3)	$0.2	$0.4	($0.2)	$1.5	74	61
12	Doubs	Transformer	AP	$1.5	($0.0)	$0.0	$1.5	$0.0	$0.0	($0.1)	($0.1)	$1.4	36	13
13	Bedington	Transformer	AP	$4.2	($0.3)	$0.1	$4.5	($3.8)	($0.2)	($2.3)	($5.8)	($1.3)	247	103
14	West	Interface	500	($12.5)	($15.3)	($2.0)	$0.8	$0.2	$0.1	$0.2	$0.3	$1.1	391	55
15	Sammis - Wylie Ridge	Line	AP	$3.0	$2.3	$1.5	$2.2	($0.2)	($0.2)	($1.0)	($1.1)	$1.1	622	101
16	Kingwood - Pruntytown	Line	AP	$1.0	($0.1)	($0.0)	$1.1	($0.0)	$0.0	$0.0	$0.0	$1.1	140	1
17	Mount Storm	Transformer	AP	($0.4)	($1.8)	($0.2)	$1.1	$0.1	$0.3	$0.1	($0.1)	$1.0	123	46
19	Krendale - Seneca	Line	AP	$0.8	$0.0	$0.2	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	225	0
23	Hamilton - Weirton	Line	AP	$0.6	$0.1	$0.1	$0.6	($0.0)	($0.1)	($0.2)	($0.0)	$0.5	138	15
25	Belmont	Transformer	AP	$0.3	($0.1)	$0.0	$0.5	($0.0)	($0.1)	($0.1)	($0.0)	$0.5	79	17

ComEd Control Zone

Table 7-45 ComEd Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 SOM, Table 7-45)

				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	($45.5)	($64.6)	($0.3)	$18.9	($1.2)	$0.5	($0.1)	($1.7)	$17.1	2,090	1,010
2	East Frankfort - Crete	Line	ComEd	($23.6)	($45.0)	($2.0)	$19.4	($2.1)	$0.7	$0.1	($2.6)	$16.8	1,650	600
3	Pleasant Valley - Belvidere	Line	ComEd	($2.7)	($12.9)	$0.8	$11.0	($0.1)	$2.0	($1.1)	($3.1)	$7.9	1,277	220
4	5004/5005 Interface	Interface	500	($13.6)	($21.0)	($0.0)	$7.4	($0.5)	($0.2)	($0.0)	($0.3)	$7.1	1,050	367
5	Bedington - Black Oak	Interface	500	($18.7)	($25.3)	($0.0)	$6.5	($0.2)	$0.1	($0.0)	($0.3)	$6.2	1,328	43
6	AEP-DOM	Interface	500	($10.4)	($16.4)	($0.4)	$5.6	($0.1)	($0.1)	$0.0	$0.1	$5.7	471	84
7	Electric Jct - Nelson	Line	ComEd	$0.4	($5.1)	$1.3	$6.8	$0.2	$0.5	($1.6)	($1.9)	$5.0	393	75
8	Rising	Flowgate	Midwest ISO	($2.4)	($7.1)	($0.0)	$4.7	($0.0)	($0.0)	$0.0	$0.0	$4.7	776	36
9	Waterman - West Dekalb	Line	ComEd	($0.9)	($4.7)	$0.4	$4.1	$0.4	$0.3	($0.1)	($0.1)	$4.1	1,496	223
10	Crete - St Johns Tap	Flowgate	Midwest ISO	($5.5)	($9.0)	($0.1)	$3.4	($0.1)	($0.1)	($0.2)	($0.3)	$3.2	330	82
11	Cloverdale - Lexington	Line	AEP	($4.8)	($7.7)	($0.1)	$2.8	($0.6)	$0.3	$0.2	($0.7)	$2.1	578	341
12	Tiltonsville - Windsor	Line	AP	($3.7)	($5.5)	($0.0)	$1.7	$0.0	$0.1	$0.0	($0.0)	$1.7	1,127	270
13	Doubs	Transformer	AP	($6.8)	($8.9)	($0.0)	$2.1	($0.3)	$0.4	$0.0	($0.6)	$1.5	536	283
14	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($2.4)	($3.6)	($0.1)	$1.1	($0.0)	($0.0)	$0.0	$0.0	$1.1	142	3
15	Sammis - Wylie Ridge	Line	AP	($1.7)	($2.8)	$0.0	$1.2	($0.0)	$0.0	$0.0	($0.1)	$1.1	494	44
17	Glidden - West Dekalb	Line	ComEd	$0.0	($0.9)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	185	0
20	Cherry Valley	Transformer	ComEd	$0.3	($0.4)	$0.1	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.7	25	3
21	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.6	($0.0)	($0.7)	($0.7)	0	82
23	Davis	Transformer	ComEd	$0.1	($0.4)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	55	0
26	Belvidere - Woodstock	Line	ComEd	$0.2	($0.2)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	49	0

Table 7-46 ComEd Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	Pleasant Valley - Belvidere	Line	ComEd	($1.9)	($19.9)	$0.1	$18.1	$0.9	$1.4	$0.0	($0.5)	$17.6	1,534	210
2	East Frankfort - Crete	Line	ComEd	($13.5)	($27.4)	($0.1)	$13.9	($0.5)	($0.5)	($0.1)	($0.1)	$13.8	1,333	161
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($29.5)	($44.6)	($2.2)	$12.9	($2.4)	($0.5)	$0.6	($1.3)	$11.6	1,713	671
4	Kammer	Transformer	500	($15.0)	($25.2)	($0.0)	$10.2	($0.4)	($0.6)	($0.1)	$0.2	$10.4	1,554	726
5	AP South	Interface	500	($18.7)	($29.2)	($0.0)	$10.4	($0.9)	($0.3)	($0.1)	($0.7)	$9.7	1,650	282
6	Crete - St Johns Tap	Flowgate	Midwest ISO	($8.5)	($17.9)	($0.2)	$9.2	($0.4)	($0.1)	($0.0)	($0.4)	$8.9	539	132
7	Sliver Lake - Cherry Valley	Line	ComEd	$0.1	($3.7)	$0.1	$3.9	$0.8	$0.2	($0.1)	$0.5	$4.3	340	41
8	Wylie Ridge	Transformer	AP	($7.9)	($10.9)	($0.0)	$3.0	($0.8)	($1.5)	$0.0	$0.8	$3.8	354	335
9	Glidden - West Dekalb	Line	ComEd	($0.2)	($3.8)	$0.0	$3.7	$0.0	$0.0	$0.0	$0.0	$3.7	668	0
10	West	Interface	500	($11.4)	($14.9)	($0.0)	$3.5	($0.0)	($0.0)	($0.0)	($0.0)	$3.5	391	55
11	Mount Storm - Pruntytown	Line	AP	($4.1)	($6.8)	($0.0)	$2.7	($0.1)	($0.3)	($0.0)	$0.3	$3.0	523	25
12	5004/5005 Interface	Interface	500	($5.1)	($7.7)	($0.0)	$2.6	($0.6)	($0.9)	($0.0)	$0.3	$2.9	334	198
13	Cloverdale - Lexington	Line	AEP	($4.2)	($7.3)	($0.0)	$3.1	($0.5)	($0.3)	($0.0)	($0.3)	$2.8	666	239
14	Electric Jct - Nelson	Line	ComEd	$0.0	($2.2)	$0.1	$2.3	$1.6	$1.0	($0.1)	$0.4	$2.8	279	118
15	Sammis - Wylie Ridge	Line	AP	($3.1)	($5.5)	($0.0)	$2.4	($0.2)	($0.1)	($0.0)	($0.1)	$2.3	622	101
16	Cherry Valley	Transformer	ComEd	$0.2	($2.0)	$0.0	$2.2	$0.0	$0.0	$0.0	($0.0)	$2.2	14	2
20	Quad Cities - Cordova	Line	ComEd	$0.2	($1.0)	$0.0	$1.3	($0.0)	$0.1	$0.0	($0.1)	$1.2	104	15
21	Burnham - Munster	Line	ComEd	($2.1)	($3.4)	($0.0)	$1.3	($0.0)	$0.0	($0.0)	($0.1)	$1.2	140	15
22	Kincaid - Pana North	Line	ComEd	($0.4)	($1.5)	($0.0)	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	281	0
24	East Frankfort - Braidwood	Line	ComEd	($0.1)	($1.1)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	8	0

DAY Control Zone

Table 7-47 DAY Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 SOM, Table 7-47)

				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	($2.6)	($4.1)	($0.4)	$1.1	($0.0)	$0.4	$0.4	($0.0)	$1.1	2,090	1,010
2	5004/5005 Interface	Interface	500	($0.7)	($1.6)	($0.0)	$0.8	$0.0	$0.1	$0.1	$0.0	$0.9	1,050	367
3	AEP-DOM	Interface	500	($0.7)	($1.4)	($0.0)	$0.7	($0.0)	($0.0)	$0.0	$0.0	$0.7	471	84
4	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	($0.0)	$0.3	$0.4	($0.0)	$0.0	($0.8)	($0.8)	($0.5)	945	80
5	Cloverdale - Lexington	Line	AEP	($0.2)	($0.6)	($0.1)	$0.4	$0.0	$0.0	$0.1	$0.1	$0.5	578	341
6	Bedington - Black Oak	Interface	500	($0.9)	($1.6)	($0.2)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.4	1,328	43
7	Electric Jct - Nelson	Line	ComEd	$0.0	$0.0	$1.1	$1.1	($0.0)	$0.0	($1.5)	($1.5)	($0.4)	393	75
8	Doubs	Transformer	AP	($0.3)	($0.6)	($0.0)	$0.2	$0.0	$0.1	$0.0	$0.0	$0.3	536	283
9	Dumont - Stillwell	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.2)	($0.2)	($0.2)	16	34
10	Fort Martin - Ronco	Line	AP	($0.0)	($0.1)	($0.0)	$0.0	($0.0)	$0.0	$0.2	$0.2	$0.2	31	42
11	Mount Storm - Pruntytown	Line	AP	($0.0)	($0.1)	($0.0)	$0.0	$0.0	$0.1	$0.2	$0.2	$0.2	87	244
12	Waterman - West Dekalb	Line	ComEd	$0.0	$0.0	$0.3	$0.3	$0.0	$0.0	($0.1)	($0.1)	$0.2	1,496	223
13	Branchburg - Flagtown	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	($0.2)	0	0
14	Tiltonsville - Windsor	Line	AP	($0.2)	($0.4)	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.1	$0.2	1,127	270
15	Pleasant Valley - Belvidere	Line	ComEd	$0.0	$0.0	$0.4	$0.4	($0.0)	$0.0	($0.6)	($0.6)	($0.1)	1,277	220

Table 7-48 DAY Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	Kammer	Transformer	500	($1.0)	($2.4)	($0.0)	$1.4	$0.2	$0.1	$0.0	$0.1	$1.5	1,554	726
2	West	Interface	500	($0.8)	($1.4)	$0.0	$0.7	$0.0	$0.0	($0.0)	$0.0	$0.7	391	55
3	AP South	Interface	500	($1.6)	($2.3)	$0.0	$0.7	$0.0	$0.2	($0.0)	($0.1)	$0.5	1,650	282
4	Wylie Ridge	Transformer	AP	($0.6)	($1.1)	($0.0)	$0.5	$0.2	$0.2	$0.0	($0.0)	$0.4	354	335
5	Cloverdale - Lexington	Line	AEP	($0.3)	($0.7)	($0.0)	$0.5	$0.0	$0.1	$0.0	($0.1)	$0.4	666	239
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.3	$0.6	$0.0	($0.3)	($0.0)	($0.0)	($0.1)	($0.1)	($0.3)	1,713	671
7	Tiltonsville - Windsor	Line	AP	($0.2)	($0.5)	($0.0)	$0.3	$0.0	$0.1	$0.0	($0.1)	$0.2	794	198
8	Marquis - Waverly	Line	AEP	($0.0)	($0.2)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	41	9
9	Sammis - Wylie Ridge	Line	AP	($0.2)	($0.4)	($0.0)	$0.2	$0.0	$0.1	($0.0)	($0.0)	$0.2	622	101
10	Pierce - Foster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.2)	($0.2)	0	4
11	5004/5005 Interface	Interface	500	($0.4)	($0.6)	$0.0	$0.2	$0.1	$0.1	($0.0)	($0.0)	$0.1	334	198
12	Kammer - Ormet	Line	AEP	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	552	509
13	East Frankfort - Crete	Line	ComEd	$0.2	$0.3	$0.0	($0.1)	($0.0)	($0.0)	($0.0)	($0.0)	($0.1)	1,333	161
14	Kanawha River	Transformer	AEP	($0.1)	($0.2)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	159	37
15	Breed - Wheatland	Line	AEP	$0.0	$0.1	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	408	0

DLCO Control Zone

Table 7-49 DLCO Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 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	Crescent	Transformer	DLCO	$10.2	$0.0	$0.2	$10.4	$0.1	($0.5)	($0.3)	$0.3	$10.7	579	124
2	AP South	Interface	500	($26.3)	($32.0)	($0.1)	$5.5	($1.4)	($0.3)	$0.2	($1.0)	$4.5	2,090	1,010
3	Collier - Elwyn	Line	DLCO	$3.7	$0.4	$0.1	$3.4	($0.0)	($0.1)	($0.0)	$0.1	$3.4	343	94
4	Bedington - Black Oak	Interface	500	($8.4)	($9.9)	($0.1)	$1.5	($0.2)	($0.1)	$0.0	($0.1)	$1.4	1,328	43
5	5004/5005 Interface	Interface	500	($6.9)	($8.6)	($0.1)	$1.6	($0.3)	($0.1)	$0.0	($0.2)	$1.4	1,050	367
6	AEP-DOM	Interface	500	($4.3)	($5.7)	($0.0)	$1.4	($0.2)	($0.1)	$0.0	($0.1)	$1.3	471	84
7	Sammis - Wylie Ridge	Line	AP	($1.7)	($3.1)	($0.0)	$1.4	($0.1)	$0.1	$0.0	($0.2)	$1.2	494	44
8	Carson - Oakland	Line	DLCO	$0.7	$0.0	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	40	0
9	East Frankfort - Crete	Line	ComEd	$0.9	$1.5	($0.0)	($0.7)	$0.1	($0.0)	($0.0)	$0.1	($0.6)	1,650	600
10	Collier	Transformer	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	8	8
11	Cloverdale - Lexington	Line	AEP	($0.7)	($1.0)	$0.0	$0.4	($0.2)	($0.0)	($0.0)	($0.2)	$0.2	578	341
12	Beaver Valley - Sammis	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	$0.0	($0.2)	($0.2)	0	8
13	Reid - Ringgold	Line	AP	($0.5)	($0.6)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	270	15
14	Crescent - Sewickly	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	12	0
15	Beaver	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.0)	($0.1)	($0.1)	0	7
20	Beaver - Sammis	Line	DLCO	($0.2)	($0.4)	($0.0)	$0.2	($0.1)	$0.3	$0.0	($0.3)	($0.1)	165	36
32	Beaver - Mansfield	Line	DLCO	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	46	0
33	Brunot Island - Collier	Line	DLCO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2	0
45	Arsenal	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0
47	Cheswick - Logans Ferry	Line	DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0

Table 7-50 DLCO Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	Sammis - Wylie Ridge	Line	AP	($4.0)	($8.0)	($0.0)	$4.0	($0.1)	$0.5	$0.0	($0.6)	$3.4	622	101
2	AP South	Interface	500	($8.4)	($11.9)	($0.0)	$3.5	($0.5)	$0.3	$0.0	($0.8)	$2.7	1,650	282
3	West	Interface	500	($3.8)	($5.5)	($0.0)	$1.6	($0.1)	$0.0	$0.0	($0.1)	$1.5	391	55
4	Logans Ferry - Universal	Line	DLCO	$0.2	($1.2)	$0.0	$1.4	$0.0	$0.1	($0.0)	($0.1)	$1.4	388	156
5	Wylie Ridge	Transformer	AP	($8.5)	($12.9)	($0.0)	$4.4	($1.2)	$2.2	$0.0	($3.3)	$1.1	354	335
6	Mount Storm - Pruntytown	Line	AP	($1.9)	($2.8)	($0.0)	$0.9	($0.1)	$0.1	$0.0	($0.1)	$0.8	523	25
7	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.1	$1.6	($0.0)	($0.5)	$0.1	$0.1	($0.0)	$0.1	($0.4)	1,713	671
8	Kammer	Transformer	500	($1.8)	($2.5)	$0.0	$0.7	($0.3)	($0.0)	($0.0)	($0.3)	$0.3	1,554	726
9	East Frankfort - Crete	Line	ComEd	$0.7	$1.0	$0.0	($0.3)	$0.0	$0.0	($0.0)	$0.0	($0.3)	1,333	161
10	Krendale - Seneca	Line	AP	($0.6)	($0.9)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	225	0
11	Cloverdale - Lexington	Line	AEP	($0.7)	($1.1)	$0.0	$0.4	($0.1)	$0.0	($0.0)	($0.1)	$0.3	666	239
12	Beaver - Clinton	Line	DLCO	$0.1	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	20	0
13	Tiltonsville - Windsor	Line	AP	($0.7)	($1.0)	($0.0)	$0.3	($0.1)	$0.0	$0.0	($0.1)	$0.2	794	198
14	Yukon	Transformer	AP	$0.1	$0.1	$0.0	$0.0	$0.0	($0.1)	($0.0)	$0.2	$0.2	123	36
15	Ruth - Turner	Line	AEP	($0.4)	($0.6)	$0.0	$0.2	($0.1)	$0.0	($0.0)	($0.1)	$0.2	639	270
16	Collier	Transformer	DLCO	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	33	0
17	Cheswick - Logans Ferry	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	49	3
20	Cheswick - Wilmerding	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	35	0
43	Crescent - Montour	Line	DLCO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	3
44	Arsenal - Highland	Line	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-51 Dominion Control Zone top congestion cost impacts (By facility): January through June 2010 (See 2009 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	AP South	Interface	500	$60.3	($18.4)	$1.3	$80.0	$1.9	$5.3	($1.1)	($4.6)	$75.5	2,090	1,010
2	Bedington - Black Oak	Interface	500	$21.2	$15.3	$1.9	$7.7	($0.2)	($0.2)	($0.3)	($0.3)	$7.5	1,328	43
3	Pleasant View	Transformer	Dominion	$0.3	$0.0	$0.0	$0.3	($4.2)	$1.4	($0.6)	($6.3)	($6.0)	31	101
4	Doubs	Transformer	AP	($1.3)	($5.7)	($0.0)	$4.4	$1.1	$0.3	$0.3	$1.1	$5.4	536	283
5	Cloverdale - Lexington	Line	AEP	$7.7	$2.2	$0.8	$6.3	($1.2)	($1.5)	($1.6)	($1.3)	$5.0	578	341
6	Ox - Francona	Line	Dominion	$3.3	($0.6)	$0.0	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	66	0
7	AEP-DOM	Interface	500	$15.3	$12.5	$0.6	$3.4	($0.1)	($0.3)	($0.1)	$0.1	$3.5	471	84
8	Ox - Glebe	Line	Dominion	$2.5	($0.7)	$0.0	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	30	0
9	Pleasant View	Line	Dominion	$1.8	$0.1	$0.1	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	32	0
10	Greenwich - Elizabeth River	Line	Dominion	$1.6	($0.2)	$0.0	$1.8	$0.0	$0.0	($0.0)	($0.0)	$1.8	32	13
11	Yadkin	Transformer	Dominion	$1.5	$0.1	$0.0	$1.5	$0.4	$0.0	($0.1)	$0.3	$1.7	26	21
12	5004/5005 Interface	Interface	500	($2.0)	($3.2)	$0.1	$1.3	$0.3	$0.3	$0.1	$0.1	$1.4	1,050	367
13	East Frankfort - Crete	Line	ComEd	$3.0	$1.8	$0.2	$1.4	($0.2)	($0.3)	($0.2)	($0.0)	$1.4	1,650	600
14	Reid - Ringgold	Line	AP	$1.6	$0.5	$0.2	$1.3	$0.0	($0.0)	($0.0)	$0.0	$1.3	270	15
15	Danville - East Danville	Line	Dominion	$6.2	$4.9	($0.1)	$1.2	($0.2)	($0.3)	($0.1)	$0.1	$1.2	879	85
16	Endless Caverns	Transformer	Dominion	$0.3	($0.7)	$0.0	$1.1	($0.0)	($0.0)	$0.0	$0.0	$1.1	283	3
17	Glebe - Jefferson	Line	Dominion	$0.8	($0.3)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	34	0
18	Chuckatuck - Benns Church	Line	Dominion	$0.9	($0.1)	($0.0)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	29	0
19	Beechwood - Kerr Dam	Line	Dominion	$0.8	($0.5)	($0.1)	$1.2	($0.2)	$0.1	$0.0	($0.3)	$1.0	303	148
20	Pleasantville - Ashburn	Line	Dominion	$0.9	$0.0	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	22	0

Table 7-52 Dominion Control Zone top congestion cost impacts (By facility): January through June 2009 (See 2009 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	AP South	Interface	500	$20.4	($16.4)	$0.3	$37.1	$1.1	($0.2)	$0.1	$1.4	$38.5	1,650	282
2	Cloverdale - Lexington	Line	AEP	$5.2	$2.3	$0.8	$3.7	($0.0)	($1.6)	($0.8)	$0.8	$4.5	666	239
3	Kammer	Transformer	500	$5.5	$4.2	$1.0	$2.3	$0.1	($0.5)	($1.1)	($0.5)	$1.8	1,554	726
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.8	$1.2	$0.1	$1.6	($0.2)	($0.5)	($0.1)	$0.2	$1.8	1,713	671
5	Beechwood - Kerr Dam	Line	Dominion	$0.9	($0.5)	($0.0)	$1.4	($0.1)	$0.1	$0.0	($0.1)	$1.3	390	155
6	Wylie Ridge	Transformer	AP	$2.5	$1.7	$0.4	$1.2	($0.1)	($0.2)	($0.4)	($0.2)	$1.0	354	335
7	West	Interface	500	($2.4)	($3.3)	$0.0	$1.0	$0.0	$0.1	$0.0	($0.1)	$0.9	391	55
8	Crozet - Dooms	Line	Dominion	$0.6	($0.3)	$0.0	$0.9	($0.3)	($0.2)	($0.0)	($0.1)	$0.8	48	26
9	Clover - Farmville	Line	Dominion	($0.0)	($0.7)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	41	0
10	Mount Storm	Transformer	AP	$1.3	$0.2	$0.1	$1.2	($0.2)	$0.0	($0.3)	($0.5)	$0.7	123	46
11	Sammis - Wylie Ridge	Line	AP	$1.1	$0.7	$0.2	$0.6	$0.0	($0.1)	($0.1)	$0.1	$0.7	622	101
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.0	$0.5	$0.1	$0.6	($0.0)	($0.2)	($0.1)	$0.0	$0.6	539	132
13	East Frankfort - Crete	Line	ComEd	$1.2	$0.7	$0.1	$0.6	($0.0)	($0.1)	($0.1)	$0.0	$0.6	1,333	161
14	Crozet - Barracks Rd	Line	Dominion	$0.8	$0.4	($0.0)	$0.4	$0.1	($0.1)	$0.0	$0.2	$0.6	35	11
15	Mount Storm - Pruntytown	Line	AP	$4.9	$4.7	$0.6	$0.8	($0.0)	($0.0)	($0.4)	($0.4)	$0.5	523	25
17	Beaumeade - Ashburn	Line	Dominion	$0.4	$0.0	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	15	0
21	Pleasantville	Transformer	Dominion	$0.2	($0.1)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	10	0
23	Ox	Transformer	Dominion	$0.2	($0.1)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	3	0
24	Dooms	Transformer	Dominion	$0.2	($0.0)	($0.0)	$0.2	($0.0)	($0.0)	$0.0	$0.0	$0.2	8	3
25	Danville - East Danville	Line	Dominion	$0.5	$0.3	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	76	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 *2010 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 2009 to 2010 planning period which covers June 1, 2009, through May 31, 2010, and the 2010 to 2011 planning period which covers June 1, 2010, through May 31, 2011.

1 87 FERC ¶ 61,054 (1999).

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 second Long Term FTR Auction was conducted during the 2009 to 2010 planning period and covers three consecutive planning periods between 2010 and 2013. The 2011 to 2014 Long Term FTR Auction results are not presented in this report because the second round has not yet been conducted. 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 accommodate simultaneously 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 2010 to 2011 planning period include the Doubs transformer and the Messick Road – Ridgeley line. Market participants can also sell FTRs. In the Annual FTR Auction for the 2010 to 2011 planning period, total FTR sell offers were 178,248 MW, up from 142,154 MW during the 2009 to 2010 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first month

(June 2010) of the 2010 to 2011 planning period, there were 487,426 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the Annual FTR Auction for the 2010 to 2011 planning period, total FTR buy bids were 1,708,556 MW, up from 1,436,335 MW during the 2009 to 2010 planning period. Total FTR self scheduled bids were 55,732 MW for the 2010 to 2011 planning period, a decrease from 68,589 MW for the 2009 to 2010 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first month (June 2010) of the 2010 to 2011 planning period, total FTR buy bids were 1,065,658 MW.

- **FTR Credit Issues.** Effective June 1, 2009, PJM implemented a number of improvements to the PJM credit management rules. There were no participant defaults during the first six months of 2010.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2010 to 2011 Annual FTR Auction was low to moderate for FTR obligations and moderate to high for FTR options. 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 evaluate the ownership of prevailing flow and counter flow FTRs, the Market Monitoring Unit (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. During the 2010 to 2011 planning period, physical entities own 53 percent of prevailing flow Annual FTRs while financial entities own 71 percent of counter flow Annual FTRs. Overall, financial entities own about 54 percent of all Annual FTRs. Financial entities own about 66 percent of prevailing flow and 77 percent of counter flow Monthly Balance of Planning Period FTRs from January 2010 through June 2010. Overall, financial entities own about 71 percent of all Monthly Balance of Planning Period FTRs.

Market Performance

- **Volume.** For the 2010 to 2011 planning period, the Annual FTR Auction cleared 231,663 MW (13.6 percent) of FTR buy bids, up from 155,612 MW (10.8 percent of demand) for the 2009 to 2010 planning period. The Annual FTR Auction also cleared 10,315 MW (5.8 percent) of FTR sell offers for the 2009 to 2010 planning period, up from 7,399 MW (5.2 percent) for the 2009 to 2010 planning period. For the first month of the 2010 to 2011 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 110,608 MW (10.4 percent) of FTR buy bids and 40,045 MW (8.2 percent) of FTR sell offers.

- **Price.** For the 2010 to 2011 planning period, 87.4 percent of the Annual FTRs were purchased for less than $1 per MWh and 93.7 percent for less than $2 per MWh. For the 2010 to 2011 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.43 per MWh for 24-hour FTRs, $0.35 per MWh for on peak FTRs and $0.32 per MWh for off peak FTRs. Comparable, weighted-average prices paid for annual buy-bid FTR obligations for the 2009 to 2010 planning period were $0.66 per MWh for 24-hour FTRs and $0.57 per MWh for on peak FTRs and $0.40 per MWh for off peak FTRs. The weighted-average prices paid for 2010 to 2011 planning period annual buy-bid FTR obligations and options were $0.35 per MWh and $0.26 per MWh, respectively, compared to $0.53 per MWh and $0.35 per MWh, respectively, in the 2009 to 2010 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 2010 to 2011 planning period was $0.29 per MWh, compared with $0.18 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2009 to 2010 planning period.

- **Revenue.** The Annual FTR Auction generated $1,049.8 million of net revenue for all FTRs during the 2010 to 2011 planning period, down from $1,329.8 million for the 2009 to 2010 planning period. The Monthly Balance of Planning Period FTR Auctions generated $2.5 million in net revenue for all FTRs during the first month of the 2010 to 2011 planning period.

- **Revenue Adequacy.** FTRs were 96.9 percent revenue adequate for the 2009 to 2010 planning period. FTRs were paid at 97.8 percent of the target allocation level for the first month of the 2010 to 2011 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $192.1 million of FTR revenues during the first month of the 2010 to 2011 planning period and $878.4 million during the 2009 to 2010 planning period. For the full twelve months of the 2009 to 2010 planning period, the top sink and top source with the highest positive FTR target allocations were

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).

the AP Control Zone and the Mount Storm aggregate, respectively. Similarly, the top sink and top source with the largest negative FTR target allocation was the Western Hub.

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 2010 to 2011 planning period were the AP South Interface and the Nelson – Electric Junction 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 were also introduced and 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 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. This is down from 140,038 MW for the 2009 to 2010 planning period with 64,988 MW bid in Stage 1A, 26,517 MW bid in Stage 1B and 48,533 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 4,660 MW of ARRs associated with approximately $67,700 per MW-day of revenue that were reassigned in the first month of the 2010 to 2011 planning period. There were 19,061 MW of ARRs associated with approximately $362,400 per MW-day of revenue that were reassigned for the full 2009 to 2010 planning period.

Market Performance

- **Volume.** 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 (54.7 percent) of these allocated ARRs as Annual FTRs. Of 140,038 MW in ARR requests for the 2009 to 2010 planning period, 109,414 MW (78.1 percent) were allocated. There were 64,914 MW allocated in Stage 1A, 26,514 MW allocated in Stage 1B and 17,986 MW allocated in Stage 2. Eligible market participants self scheduled 68,589 MW (62.7 percent) of these allocated ARRs as Annual FTRs.

- **Revenue.** As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

- **Revenue Adequacy.** During the 2010 to 2011 planning period, ARR holders will receive $1,028.8 million in ARR credits, with an average hourly ARR credit of $1.15 per MWh. During the 2010 to 2011 planning period, the ARR target allocations were $1,028.8 million while PJM collected $1,052.3 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through Jun 30, 2010, making ARRs revenue adequate. During the 2009 to 2010 planning period, ARR holders received $1,273.5 million in ARR credits, with an average hourly ARR credit of $1.33 per MWh. For the 2009 to 2010 planning period, the ARR target allocations were $1,273.5 million while PJM collected $1,349.3 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** When ARRs were allocated for the 2010 to 2011 planning period, some of the requested ARRs were prorated in Stage 2 as a result of binding transmission constraints. No ARRs were prorated in Stage 1A and Stage 1B since there were no constraints limiting the ARR allocation in these two stages.

- **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 first is to compare the revenue received by ARR holders to the congestion costs experienced by these ARR holders. The second is to compare the revenue received by FTR holders to the total congestion costs within PJM. The final and comprehensive method is to compare the revenue received by all ARR and FTR holders to total actual congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. During the 2008 to 2009 planning period, total ARR and FTR revenues hedged more than 100 percent of the congestion costs within PJM. For the 2009 to 2010 planning period, all ARRs and FTRs hedged 96.4 percent of the congestion costs within PJM.

- **ARRs and FTRs as a Hedge against Total Energy Costs.** The hedge provided by ARRs can also be measured by comparing the value of the ARR and self-scheduled FTRs that sink in a zone to the cost of real time energy in the zone. This is a measure of the value of the hedge against real time energy costs provided by ARRs received by loads during this period. The total value of ARRs was 3.9 percent of the total real time energy charges for January through June of 2010. The hedge provided by FTRs can also be measured by comparing the value of the FTRs that sink in a zone to the cost of real time energy in the zone. The total net value of FTRs was 0.3 percent of the total real time energy charges for January through June 2010. When combined, the sum is a measure of the total value of ARRs plus FTRs. The total value of ARRs plus FTRs was 4.2 percent of the total real time energy charges for January through June 2010.

Conclusion

The annual ARR allocation and the FTR auctions provide market participants with hedging instruments. These instruments can be used for hedging positions or for speculation. 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. The MMU recommends that the rules for ARR reassignment when load shifts should address the fact that in the case of ARRs self scheduled as FTRs, the underlying FTRs do not follow the load while the ARRs do.

ARRs were 100 percent revenue adequate for both the 2009 to 2010 and the 2010 to 2011 planning periods. FTRs were paid at 96.9 percent of the target allocation level for the 12-month period of the 2009 to 2010 planning period, and at 97.8 percent of the target allocation level for the first month of the 2010 to 2011 planning 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 adequacy of FTRs as a hedge against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.

The total of ARR and FTR revenues hedged more than 100 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2008 to 2009 planning period and 96.4 percent of the congestion costs in PJM during the 2009 to 2010 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 FTR holders, their revenues or those paying congestion.

Financial Transmission Rights

Supply

Table 8-1 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2010 to 2011 (See 2009 SOM Table 8-2)

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Doubs	Transformer	AP	2	1	2	1
Messick Road - Ridgeley	Line	AP	1	2	1	5
Mahans Lane - Tidd	Line	AEP	3	5	8	9
Middlebourne - Willow Island	Line	AP	4	4	4	3
AP South	Interface	AP	5	3	3	2
Endless Caverns	Transformer	Dominion	8	6	6	4
Tiltonsville - Windsor	Line	AP	43	29	7	6
Smith - Wylie Ridge	Line	AP	13	7	5	7
Roxbury - Shade Gap	Line	PENELEC	6	8	12	15
Krendale - Seneca	Line	AP	7	9	10	8

Patterns of Ownership

Table 8-2 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2010 to 2011 (See 2009 SOM Table 8-4)

		FTR Direction		
Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Physical	Yes	25.0%	2.7%	18.7%
	No	27.5%	26.3%	27.1%
	Total	52.5%	29.0%	45.8%
Financial	No	47.5%	71.0%	54.2%
Total		100.0%	100.0%	100.0%

Table 8-3 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through June 2010 (See 2009 SOM Table 8-5)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	34.4%	23.0%	29.3%
Financial	65.6%	77.0%	70.7%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-4 Comparison of self scheduled FTRs: Planning periods 2008 to 2009, 2009 to 2010 and 2010 to 2011 (See 2009 SOM Table 8-8)

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	109,413	62.7%
2010/2011	55,732	101,843	54.7%

Table 8-5 Annual FTR Auction market volume: Planning period 2010 to 2011 (See 2009 SOM Table 8-7)

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	76,794	300,085	73,956	24.6%	226,129	75.4%
		Prevailing Flow	195,599	1,233,329	127,366	10.3%	1,105,963	89.7%
		Total	272,393	1,533,414	201,322	13.1%	1,332,092	86.9%
	Options	Counter Flow	100	10,855	5,455	50.3%	5,400	49.7%
		Prevailing Flow	7,569	164,287	24,885	15.1%	139,402	84.9%
		Total	7,669	175,142	30,340	17.3%	144,802	82.7%
	Total	Counter Flow	76,894	310,940	79,411	25.5%	231,529	74.5%
		Prevailing Flow	203,168	1,397,616	152,251	10.9%	1,245,365	89.1%
		Total	280,062	1,708,556	231,663	13.6%	1,476,893	86.4%
Self-scheduled bids	Obligations	Counter Flow	160	2,253	2,253	100.0%	0	0.0%
		Prevailing Flow	8,644	53,479	53,479	100.0%	0	0.0%
		Total	8,804	55,732	55,732	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	76,954	302,338	76,209	25.2%	226,129	74.8%
		Prevailing Flow	204,243	1,286,808	180,845	14.1%	1,105,963	85.9%
		Total	281,197	1,589,146	257,054	16.2%	1,332,092	83.8%
	Options	Counter Flow	100	10,855	5,455	50.3%	5,400	49.7%
		Prevailing Flow	7,569	164,287	24,885	15.1%	139,402	84.9%
		Total	7,669	175,142	30,340	17.3%	144,802	82.7%
	Total	Counter Flow	77,054	313,193	81,664	26.1%	231,529	73.9%
		Prevailing Flow	211,812	1,451,095	205,730	14.2%	1,245,365	85.8%
		Total	288,866	1,764,288	287,394	16.3%	1,476,893	83.7%
Sell offers	Obligations	Counter Flow	18,898	60,966	2,360	3.9%	58,606	96.1%
		Prevailing Flow	28,599	106,947	7,914	7.4%	99,033	92.6%
		Total	47,497	167,912	10,274	6.1%	157,638	93.9%
	Options	Counter Flow	136	3,060	0	0.0%	3,060	100.0%
		Prevailing Flow	1,747	7,455	41	0.5%	7,415	99.5%
		Total	1,883	10,515	41	0.4%	10,475	99.6%
	Total	Counter Flow	19,034	64,026	2,360	3.7%	61,666	96.3%
		Prevailing Flow	30,346	114,402	7,955	7.0%	106,447	93.0%
		Total	49,380	178,428	10,315	5.8%	168,113	94.2%

Table 8-6 Monthly Balance of Planning Period FTR Auction market volume: January through June 2010 (See 2009 SOM Table 8-9)

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-10	Obligations	Buy bids	156,274	716,812	79,724	11.1%	637,088	88.9%
		Sell offers	46,206	165,858	11,224	6.8%	154,635	93.2%
	Options	Buy bids	391	11,953	1,621	13.6%	10,332	86.4%
		Sell offers	1,579	33,020	5,686	17.2%	27,334	82.8%
Feb-10	Obligations	Buy bids	129,946	656,279	78,354	11.9%	577,925	88.1%
		Sell offers	40,605	146,757	10,364	7.1%	136,393	92.9%
	Options	Buy bids	622	13,993	1,119	8.0%	12,874	92.0%
		Sell offers	1,702	33,125	6,955	21.0%	26,170	79.0%
Mar-10	Obligations	Buy bids	120,727	607,270	90,189	14.9%	517,081	85.1%
		Sell offers	56,858	201,797	12,542	6.2%	189,255	93.8%
	Options	Buy bids	331	8,420	749	8.9%	7,672	91.1%
		Sell offers	1,224	23,960	5,326	22.2%	18,634	77.8%
Apr-10	Obligations	Buy bids	104,078	483,995	78,853	16.3%	405,142	83.7%
		Sell offers	30,097	127,238	9,844	7.7%	117,394	92.3%
	Options	Buy bids	185	5,643	481	8.5%	5,161	91.5%
		Sell offers	980	17,098	3,474	20.3%	13,625	79.7%
May-10	Obligations	Buy bids	83,069	372,583	63,260	17.0%	309,323	83.0%
		Sell offers	16,709	74,617	8,385	11.2%	66,233	88.8%
	Options	Buy bids	396	3,229	209	6.5%	3,020	93.5%
		Sell offers	623	9,657	3,049	31.6%	6,609	68.4%
Jun-10	Obligations	Buy bids	204,305	998,923	107,676	10.8%	891,247	89.2%
		Sell offers	94,433	417,735	24,228	5.8%	393,507	94.2%
	Options	Buy bids	1,725	66,735	2,932	4.4%	63,804	95.6%
		Sell offers	11,073	69,691	15,816	22.7%	53,874	77.3%
2009/2010*	Obligations	Buy bids	1,908,766	8,003,573	946,107	11.8%	7,057,466	88.2%
		Sell offers	649,057	2,337,381	181,810	7.8%	2,155,571	92.2%
	Options	Buy bids	4,904	216,423	17,194	7.9%	199,228	92.1%
		Sell offers	29,328	458,584	72,335	15.8%	386,248	84.2%
2010/2011*	Obligations	Buy bids	204,305	998,923	107,676	10.8%	891,247	89.2%
		Sell offers	94,433	417,735	24,228	5.8%	393,507	94.2%
	Options	Buy bids	1,725	66,735	2,932	4.4%	63,804	95.6%
		Sell offers	11,073	69,691	15,816	22.7%	53,874	77.3%

* Shows twelve months for 2009/2010 and one month ended 30-Jun-2010 for 2010/2011

Table 8-7 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January through June 2010 (See 2009 SOM Table 8-10)

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-10	Bid	393,426	127,235	90,338				117,766	728,765
	Cleared	55,052	10,039	5,963				10,290	81,345
Feb-10	Bid	363,548	100,591	91,281				114,853	670,272
	Cleared	53,791	9,948	6,304				9,430	79,473
Mar-10	Bid	374,155	108,329	106,100				27,107	615,690
	Cleared	66,677	10,555	9,864				3,842	90,938
Apr-10	Bid	366,026	123,612						489,638
	Cleared	67,471	11,863						79,334
May-10	Bid	375,812							375,812
	Cleared	63,469							63,469
Jun-10	Bid	398,343	134,107	127,474	27,614	129,012	126,849	122,260	1,065,658
	Cleared	65,245	9,590	9,386	2,996	10,408	7,927	5,054	110,608

Table 8-8 Secondary bilateral FTR market volume: Planning periods 2009 to 2010 and 2010 to 2011[3] (See 2009 SOM Table 8-11)

Planning Period	Hedge Type	Class Type	Volume (MW)	Price
2009/2010	Obligation	24-Hour	1,468	$0.38
		On Peak	3,544	($0.01)
		Off Peak	3,798	($0.06)
		Total	8,811	$0.31
	Option	24-Hour	30	$5.93
		On Peak	0	NA
		Off Peak	0	NA
		Total	30	$5.93
2010/2011*	Obligation	24-Hour	1,537	$0.06
		On Peak	69	$0.03
		Off Peak	77	$0.02
		Total	1,683	$0.06
	Option	24-Hour	20	$0.40
		On Peak	0	NA
		Off Peak	0	NA
		Total	20	$0.40

* Shows one month ended 30-Jun-2010

3 The 2010 to 2011 planning period covers the 2010 to 2011 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through June 30, 2010.

Price

Table 8-9 Annual FTR Auction weighted-average cleared prices by FTR direction (Dollars per MWh): Planning period 2010 to 2011 (See 2009 SOM Table 8-13)

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.56)	($0.34)	($0.28)	($0.35)
		Prevailing Flow	$0.97	$0.73	$0.69	$0.75
		Total	$0.43	$0.35	$0.32	$0.35
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.00	$0.41	$0.17	$0.31
		Total	$1.00	$0.33	$0.14	$0.26
Self-scheduled bids	Obligations	Counter Flow	($0.15)	NA	NA	($0.15)
		Prevailing Flow	$1.48	NA	NA	$1.48
		Total	$1.41	NA	NA	$1.41
Buy and self-scheduled bids	Obligations	Counter Flow	($0.46)	($0.34)	($0.28)	($0.34)
		Prevailing Flow	$1.38	$0.73	$0.69	$1.07
		Total	$1.17	$0.35	$0.32	$0.71
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.00	$0.41	$0.17	$0.31
		Total	$1.00	$0.33	$0.14	$0.26
Sell offers	Obligations	Counter Flow	($0.15)	($0.57)	($0.43)	($0.47)
		Prevailing Flow	$0.45	$0.53	$0.32	$0.43
		Total	$0.22	$0.32	$0.12	$0.22
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$1.11	$0.33	$0.66
		Total	$0.00	$1.11	$0.33	$0.66

Figure 8-1 Annual FTR auction clearing price duration curves: Planning period 2010 to 2011 (See 2009 SOM Figure 8-2)

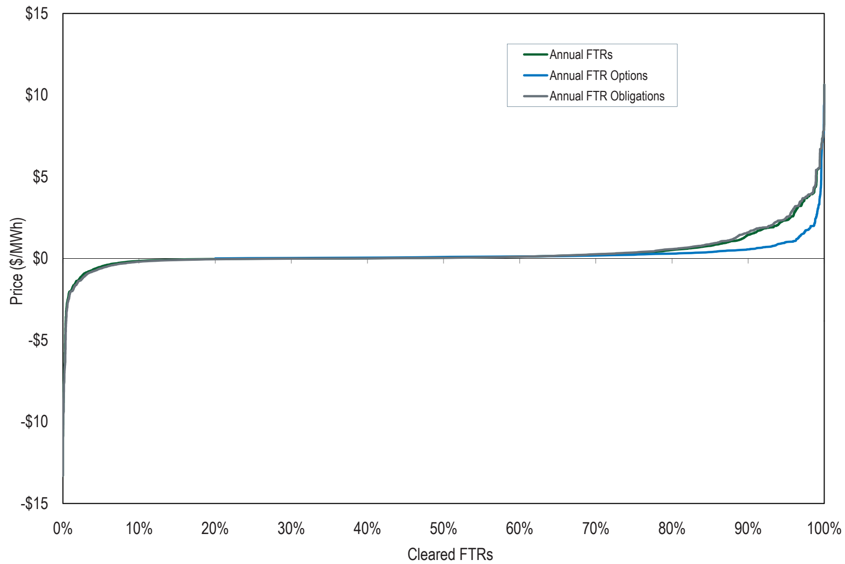


Table 8-10 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January through June 2010 (See 2009 SOM Table 8-14)

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-10	$0.09	$0.34	($0.01)				$0.16	$0.13
Feb-10	$0.09	$0.31	$0.17				$0.31	$0.19
Mar-10	$0.14	$0.30	$0.34				($0.07)	$0.15
Apr-10	$0.10	$0.24						$0.12
May-10	$0.06							$0.06
Jun-10	$0.11	$0.36	$0.35	$0.80	$0.33	$0.40	$0.37	$0.29

Revenue

Annual FTR Auction Revenue

Table 8-11 Annual FTR Auction revenue by FTR direction: Planning period 2010 to 2011 (See 2009 SOM Table 8-16)

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($31,703,144)	($48,028,679)	($43,231,947)	($122,963,770)
		Prevailing Flow	$101,156,043	$184,829,000	$172,777,067	$458,762,110
		Total	$69,452,899	$136,800,321	$129,545,120	$335,798,340
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$4,190,505	$20,643,158	$9,781,679	$34,615,342
		Total	$4,190,505	$20,643,158	$9,781,679	$34,615,342
	Total	Counter Flow	($31,703,144)	($48,028,679)	($43,231,947)	($122,963,770)
		Prevailing Flow	$105,346,548	$205,472,159	$182,558,746	$493,377,453
		Total	$73,643,404	$157,443,479	$139,326,799	$370,413,682
Self-scheduled bids	Obligations	Counter Flow	($3,013,115)	NA	NA	($3,013,115)
		Prevailing Flow	$692,601,293	NA	NA	$692,601,293
		Total	$689,588,178	NA	NA	$689,588,178
Buy and self-scheduled bids	Obligations	Counter Flow	($34,716,259)	($48,028,679)	($43,231,947)	($125,976,885)
		Prevailing Flow	$793,757,336	$184,829,000	$172,777,067	$1,151,363,403
		Total	$759,041,077	$136,800,321	$129,545,120	$1,025,386,518
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$4,190,505	$20,643,158	$9,781,679	$34,615,342
		Total	$4,190,505	$20,643,158	$9,781,679	$34,615,342
	Total	Counter Flow	($34,716,259)	($48,028,679)	($43,231,947)	($125,976,885)
		Prevailing Flow	$797,947,840	$205,472,159	$182,558,746	$1,185,978,745
		Total	$763,231,581	$157,443,479	$139,326,799	$1,060,001,860
Sell offers	Obligations	Counter Flow	($100,949)	($2,404,436)	($2,499,147)	($5,004,532)
		Prevailing Flow	$492,925	$9,363,404	$5,201,761	$15,058,090
		Total	$391,976	$6,958,967	$2,702,614	$10,053,558
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$85,206	$34,159	$119,365
		Total	$0	$85,206	$34,159	$119,365
	Total	Counter Flow	($100,949)	($2,404,436)	($2,499,147)	($5,004,532)
		Prevailing Flow	$492,925	$9,448,610	$5,235,920	$15,177,455
		Total	$391,976	$7,044,173	$2,736,773	$10,172,923

Figure 8-2 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2010 to 2011[4] (See 2009 SOM Figure 8-5)

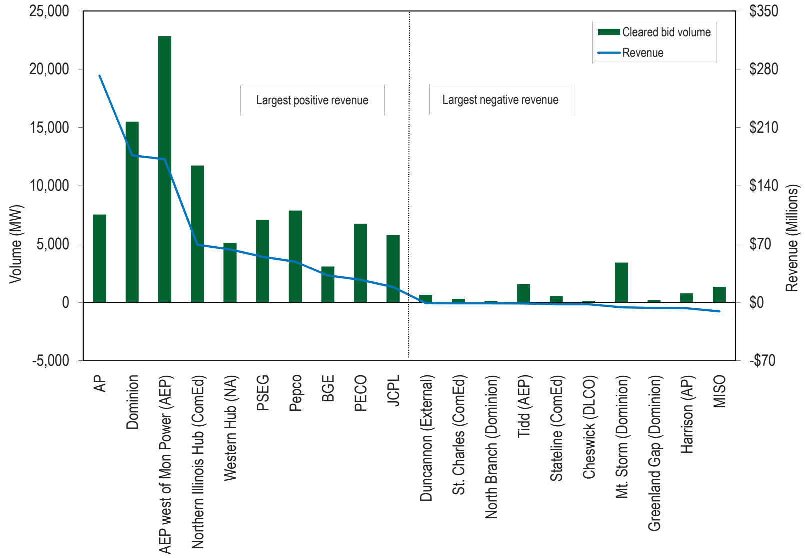
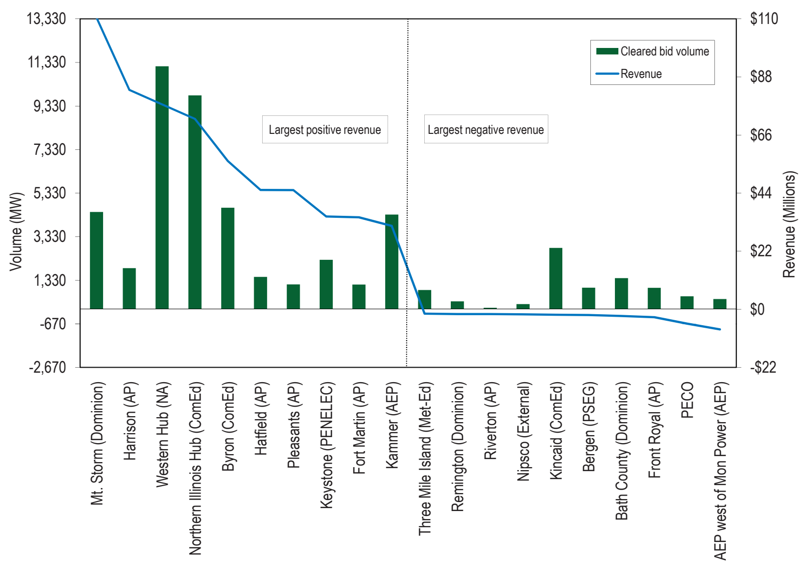


Figure 8-3 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2010 to 2011 (See 2009 SOM Figure 8-6)



4 For Figure 8-2 through Figure 8-7, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Monthly Balance of Planning Period FTR Auction Revenue

Table 8-12 Monthly Balance of Planning Period FTR Auction revenue: January through June 2010 (See 2009 SOM Table 8-17)

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-10	Obligations	Buy bids	($358,507)	$3,027,607	$1,763,504	$4,432,604
		Sell offers	$383,960	$1,556,699	$561,863	$2,502,522
	Options	Buy bids	$0	$341,524	$118,211	$459,735
		Sell offers	$83,413	$542,599	$261,153	$887,164
Feb-10	Obligations	Buy bids	$530,509	$2,872,273	$2,657,432	$6,060,214
		Sell offers	($116,080)	$1,524,315	$1,983,143	$3,391,378
	Options	Buy bids	$0	$241,692	$234,325	$476,018
		Sell offers	$8,606	$825,079	$709,563	$1,543,248
Mar-10	Obligations	Buy bids	($549,382)	$4,005,065	$2,109,386	$5,565,069
		Sell offers	$565,634	$1,299,894	$578,118	$2,443,646
	Options	Buy bids	$972	$27,948	$25,433	$54,353
		Sell offers	$80,862	$900,428	$434,215	$1,415,505
Apr-10	Obligations	Buy bids	($455,673)	$1,949,169	$1,914,146	$3,407,643
		Sell offers	$411,821	$303,177	$711,735	$1,426,734
	Options	Buy bids	$0	$31,664	$7,685	$39,348
		Sell offers	$397	$619,455	$222,426	$842,278
May-10	Obligations	Buy bids	($174,016)	$796,256	$742,930	$1,365,170
		Sell offers	$55,656	$98,700	$324,803	$479,159
	Options	Buy bids	$0	$38,754	$2,044	$40,798
		Sell offers	$30	$400,162	$143,440	$543,632
Jun-10	Obligations	Buy bids	$3,248,555	$8,066,567	$6,097,873	$17,412,995
		Sell offers	$953,733	$3,876,255	$3,725,334	$8,555,322
	Options	Buy bids	$5,802	$158,851	$116,761	$281,415
		Sell offers	$16,839	$4,265,630	$2,393,988	$6,676,457
2009/2010*	Obligations	Buy bids	($121,010)	$45,775,003	$33,593,366	$79,247,359
		Sell offers	$3,920,764	$21,760,177	$17,779,192	$43,460,133
	Options	Buy bids	$98,620	$1,940,920	$834,871	$2,874,411
		Sell offers	$263,053	$11,631,451	$7,274,458	$19,168,962
2010/2011*	Obligations	Buy bids	$3,248,555	$8,066,567	$6,097,873	$17,412,995
		Sell offers	$953,733	$3,876,255	$3,725,334	$8,555,322
	Options	Buy bids	$5,802	$158,851	$116,761	$281,415
		Sell offers	$16,839	$4,265,630	$2,393,988	$6,676,457

* Shows twelve months for 2009/2010 and one month ended 30-Jun-2010 for 2010/2011

Figure 8-4 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 (See 2009 SOM Figure 8-7)

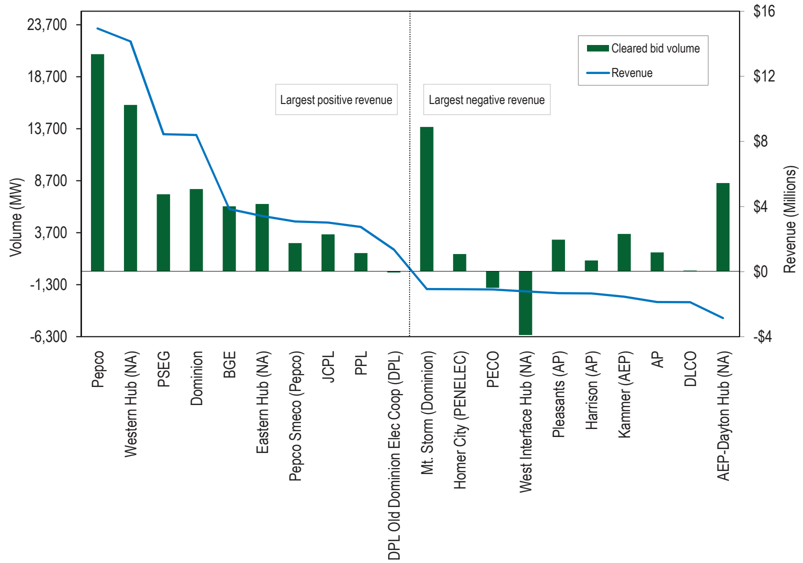
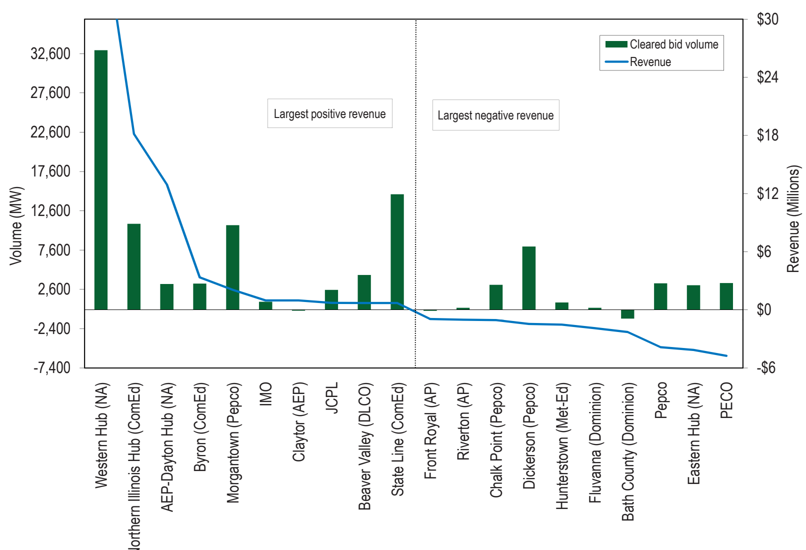


Figure 8-5 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 (See 2009 SOM Figure 8-8)



Revenue Adequacy

Table 8-13 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011 (See 2009 SOM Table 8-18)

Accounting Element	2009/2010	2010/2011*
ARR information		
ARR target allocations	$1,276.9	$84.6
FTR auction revenue	$1,368.7	$89.1
ARR excess	$91.9	$4.5
FTR targets		
FTR target allocations	$908.1	$196.4
Adjustments:		
Adjustments to FTR target allocations	($1.5)	$0.0
Total FTR targets	$906.6	$196.4
FTR revenues		
ARR excess	$91.9	$4.5
Competing uses	$0.0	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($37.8)	($0.6)
Hourly congestion revenue	$854.9	$189.2
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($31.0)	($0.9)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($2.0)	($0.1)
Adjustments:		
Excess revenues carried forward into future months	$27.3	$0.0
Excess revenues distributed back to previous months	$9.2	$0.0
Other adjustments to FTR revenues	$2.4	$0.0
Total FTR revenues	$923.5	$192.1
Excess revenues distributed to other months	($45.1)	$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	$878.4	$192.1
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$880.3	$192.2
Remaining deficiency	$28.3	$4.3

* Shows one month ended 30-Jun-10

Table 8-14 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011 (See 2009 SOM Table 8-19)

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Credits Deficiency (with adjustments)	Credits Excess (with adjustments)
Jun-09	$54.6	$43.9	100.0%	$43.9	100.0%	$0.0	$0.0
Jul-09	$53.2	$40.4	100.0%	$40.4	100.0%	$0.0	$0.0
Aug-09	$92.4	$92.4	81.3%	$92.4	100.0%	$0.0	$0.0
Sep-09	$31.4	$31.4	87.4%	$31.4	100.0%	$0.0	$0.0
Oct-09	$57.8	$57.8	83.4%	$57.8	100.0%	$0.0	$0.0
Nov-09	$38.2	$37.9	100.0%	$37.9	100.0%	$0.0	$0.0
Dec-09	$101.9	$93.7	100.0%	$93.7	100.0%	$0.0	$0.0
Jan-10	$223.7	$213.0	100.0%	$213.0	100.0%	$0.0	$0.0
Feb-10	$113.3	$110.9	100.0%	$110.9	100.0%	$0.0	$0.0
Mar-10	$29.0	$35.8	73.9%	$29.0	81.1%	$6.8	$0.0
Apr-10	$47.7	$68.5	69.3%	$47.7	69.7%	$20.8	$0.0
May-10	$80.2	$80.9	99.1%	$80.2	99.1%	$0.7	$0.0
Summary for Planning Period 2009 to 2010							
Total		$906.6		$878.4	96.9%	$28.3	$0.0
Jun-10	$192.1	$196.4	97.8%	$192.1	97.8%	$4.3	$0.0
Summary for Planning Period 2010 to 2011 through June 30, 2010							
Total		$196.4		$192.1	97.8%	$4.3	$0.0

Figure 8-6 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2009 to 2010 (See 2009 SOM Figure 8-9)

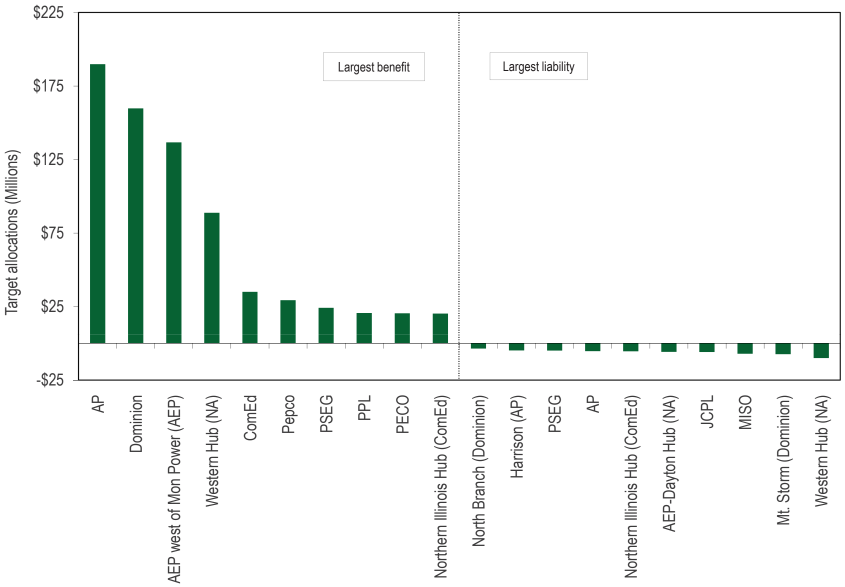
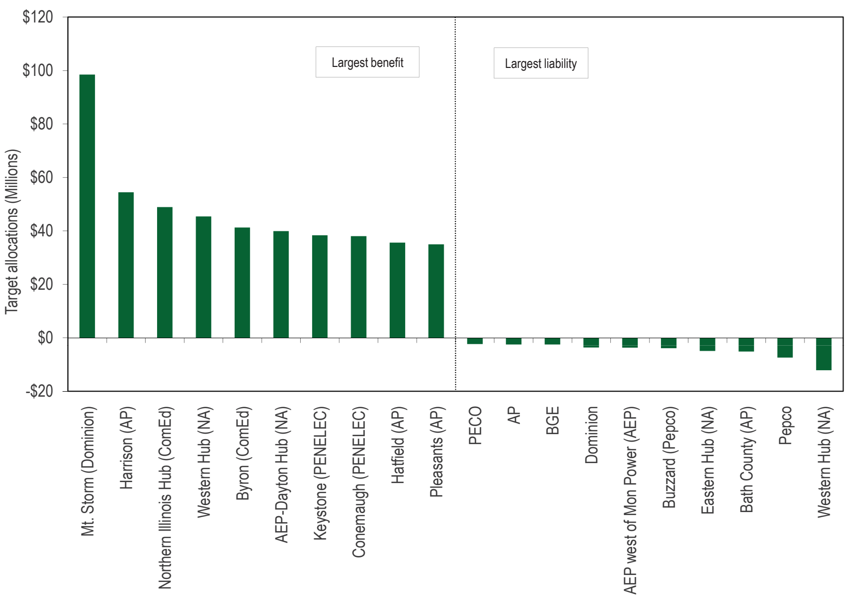


Figure 8-7 Ten largest positive and negative FTR target allocations summed by source: Planning period 2009 to 2010 (See 2009 SOM Figure 8-10)



Auction Revenue Rights

Market Structure

Supply

Incremental ARRs

Table 8-15 Incremental ARR allocation volume: Planning periods 2008 to 2009, 2009 to 2010 and 2010 to 2011 (See 2009 SOM Table 8-20)

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	15	595	595	100%	0	0%

Table 8-16 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2010 to 2011 (See 2009 SOM Table 8-21)

Constraint	Type	Control Zone
AP South	Interface	AP
Nelson - Electric Junction	Line	ComEd
State Line - Wolf Lake	Flowgate	MISO
Cedar Grove - Clifton	Line	PSEG
Roseland - Whippany	Line	JCPL
Brandon Shores - Riverside	Line	BGE
Waterman	Interface	ComEd
Linden - North Ave	Line	PSEG
Bayonne - Pleasant Valley	Line	PSEG
Cumberland - Juniata	Line	PPL

ARR Reassignment for Retail Load Switching

Table 8-17 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2009, through June 30, 2010 (See 2009 SOM Table 8-22)

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
	2009/2010	2010/2011	2009/2010	2010/2011
Control Zone	(12 months)	(1 month)*	(12 months)	(1 month)*
AECO	417	101	$7.6	$0.5
AEP	268	35	$6.3	$0.7
AP	629	227	$77.2	$22.0
BGE	2,992	698	$62.9	$9.4
ComEd	3,145	809	$10.2	$9.2
DAY	21	26	$0.1	$0.1
DLCO	371	68	$1.0	$0.4
Dominion	0	0	$0.0	$0.0
DPL	952	251	$10.9	$2.0
JCPL	1,151	476	$17.7	$3.4
Met-Ed	33	52	$0.8	$0.7
PECO	29	5	$0.5	$0.0
PENELEC	8	7	$0.2	$0.1
Pepco	2,511	620	$25.6	$6.2
PPL	4,489	763	$91.4	$7.5
PSEG	1,984	441	$50.0	$5.5
RECO	62	83	$0.0	$0.0
Total	19,061	4,660	$362.4	$67.7

* Through 30-Jun-10

Market Performance

Volume

Table 8-18 Annual ARR allocation volume: Planning periods 2009 to 2010 and 2010 to 2011 (See 2009 SOM Table 8-23)

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2009/2010	1A	0	7,527	64,988	64,914	99.9%	74	0.1%
	1B	1	3,582	26,517	26,514	100.0%	3	0.0%
	2	2	1,580	16,521	5,680	34.4%	10,841	65.6%
		3	1,157	16,413	6,013	36.6%	10,400	63.4%
		4	994	15,599	6,293	40.3%	9,306	59.7%
		Total	3,731	48,533	17,986	37.1%	30,547	62.9%
	Total		14,840	140,038	109,414	78.1%	30,624	21.9%
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%

Revenue Adequacy

Table 8-19 ARR revenue adequacy (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011 (See 2009 SOM Table 8-24)

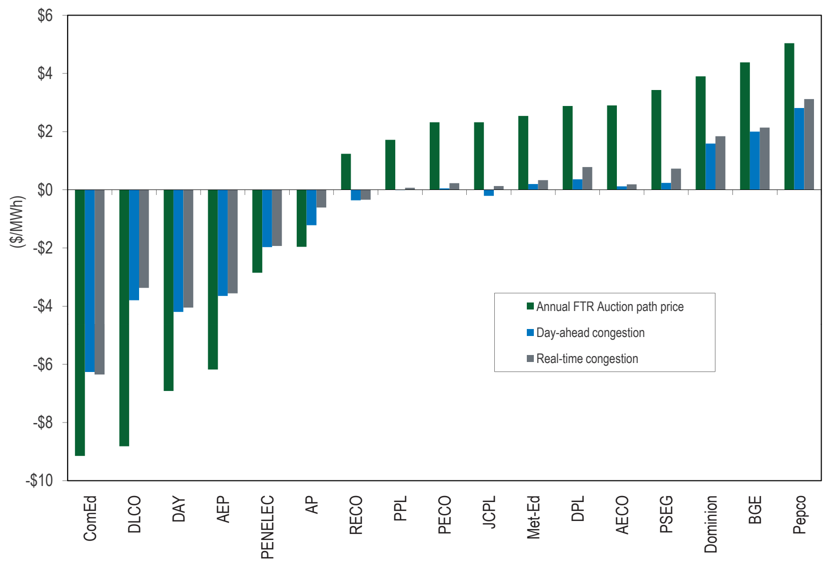
	2009/2010	2010/2011
Total FTR auction net revenue	$1,349.3	$1,052.3
Annual FTR Auction net revenue	$1,329.8	$1,049.8
Monthly Balance of Planning Period FTR Auction net revenue*	$19.5	$2.5
ARR target allocations	$1,273.5	$1,028.8
ARR credits	$1,273.5	$1,028.8
Surplus auction revenue	$75.8	$23.5
ARR payout ratio	100%	100%
FTR payout ratio*	96.9%	97.8%

* Shows twelve months for 2009/2010 and one month ended 30-Jun-10 for 2010/2011

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

Figure 8-8 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2009 to 2010 (See 2009 SOM Figure 8-11)



Effectiveness of ARRs as a Hedge against Congestion

Table 8-20 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2009 to 2010 (See 2009 SOM Table 8-25)

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$16,334,067	$594,669	$16,928,736	$16,326,233	$602,503	>100%
AEP	$4,284,698	$144,069,787	$148,354,485	$113,350,311	$35,004,174	>100%
AP	$45,451,856	$183,064,919	$228,516,775	$44,321,527	$184,195,248	>100%
BGE	$46,459,694	$2,847,697	$49,307,391	$7,167,019	$42,140,372	>100%
ComEd	$14,549,758	$30,963,973	$45,513,731	$72,332,001	($26,818,270)	62.9%
DAY	$6,207,117	$801,013	$7,008,130	$10,354,069	($3,345,940)	67.7%
DLCO	$2,450,918	$1,801	$2,452,719	$21,999,718	($19,546,999)	11.1%
Dominion	$6,134,065	$145,819,810	$151,953,875	$64,100,854	$87,853,021	>100%
DPL	$16,378,603	$799,792	$17,178,395	$28,137,137	($10,958,742)	61.1%
JCPL	$28,119,166	$954,861	$29,074,027	$20,415,639	$8,658,387	>100%
Met-Ed	$108,900	$11,784,177	$11,893,077	$18,641,318	($6,748,241)	63.8%
PECO	$1,932,121	$18,391,851	$20,323,972	($20,878,937)	$41,202,909	>100%
PENELEC	$22,966,832	$12,204,795	$35,171,627	$12,468,345	$22,703,282	>100%
Pepco	$21,798,040	$1,724,179	$23,522,219	$141,758,785	($118,236,566)	16.6%
PJM	$7,727,385	($153,147)	$7,574,238	$2,456,107	$5,118,131	>100%
PPL	$1,102,352	$14,750,503	$15,852,855	($24,767,326)	$40,620,180	>100%
PSEG	$83,906,675	$3,078,677	$86,985,352	$9,011,915	$77,973,437	>100%
RECO	($41,455)	$0	($41,455)	$1,285,257	($1,326,712)	0%
Total	$325,870,792	$571,699,358	$897,570,150	$538,479,974	$359,090,175	>100%

Effectiveness of FTRs as a Hedge against Congestion

Table 8-21 FTR congestion hedging by control zone: Planning period 2009 to 2010 (See 2009 SOM Table 8-26)

Control Zone	FTR Direction	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
AECO	Counter Flow	($574,550)	($2,125,313)	$1,532,321			
	Prevailing Flow	$4,794,271	$26,600,621	($21,652,461)			
	Total	$4,219,721	$24,475,307	($20,120,140)	$10,817,043	($30,937,183)	<0%
AEP	Counter Flow	($16,529,319)	($35,070,154)	$18,010,272			
	Prevailing Flow	$174,448,337	$253,485,172	($73,437,348)			
	Total	$157,919,018	$218,415,019	($55,427,076)	$101,031,029	($156,458,105)	<0%
AP	Counter Flow	($18,280,127)	($26,190,585)	$7,323,698			
	Prevailing Flow	$204,054,777	$354,899,348	($144,294,768)			
	Total	$185,774,650	$328,708,762	($136,971,070)	$132,996,453	($269,967,523)	<0%
BGE	Counter Flow	$558,288	($3,704,741)	$4,280,949			
	Prevailing Flow	$29,219,788	$39,534,833	($9,377,141)			
	Total	$29,778,076	$35,830,093	($5,096,193)	$40,787,754	($45,883,947)	<0%
ComEd	Counter Flow	($9,514,021)	($26,767,299)	$16,947,895			
	Prevailing Flow	$71,215,921	$39,946,826	$33,555,002			
	Total	$61,701,900	$13,179,527	$50,502,897	$192,953,092	($142,450,195)	26.2%
DAY	Counter Flow	($1,630,951)	($3,269,555)	$1,586,254			
	Prevailing Flow	$2,839,802	$3,425,410	($494,455)			
	Total	$1,208,852	$155,855	$1,091,799	$7,993,310	($6,901,511)	13.7%
DLCO	Counter Flow	$1,356,126	($7,042,462)	$8,442,117			
	Prevailing Flow	$9,417,471	$3,500,693	$6,219,062			
	Total	$10,773,597	($3,541,768)	$14,661,179	$25,084,077	($10,422,898)	58.4%
Dominion	Counter Flow	($13,657,681)	($22,663,539)	$8,567,470			
	Prevailing Flow	$170,375,880	$256,508,243	($80,663,595)			
	Total	$156,718,199	$233,844,704	($72,096,125)	$150,288,685	($222,384,810)	<0%
DPL	Counter Flow	($1,298,257)	($3,516,003)	$2,176,074			
	Prevailing Flow	$14,579,703	$38,653,745	($23,606,058)			
	Total	$13,281,446	$35,137,741	($21,429,984)	$28,398,375	($49,828,359)	<0%
JCPL	Counter Flow	($2,387,439)	($4,574,033)	$2,109,961			
	Prevailing Flow	$1,497,365	$48,058,948	($46,513,520)			
	Total	($890,074)	$43,484,916	($44,403,559)	$18,958,788	($63,362,348)	<0%

Table 8-21 FTR congestion hedging by control zone: Planning period 2009 to 2010 (See 2009 SOM Table 8-26) [continued]

Control Zone	FTR Direction	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
Met-Ed	Counter Flow	($1,585,783)	($2,404,120)	$767,436			
	Prevailing Flow	$17,054,016	$35,665,942	($18,064,522)			
	Total	$15,468,232	$33,261,822	($17,297,086)	$4,609,666	($21,906,752)	<0%
PECO	Counter Flow	($294,222)	($2,663,493)	$2,359,827			
	Prevailing Flow	$21,761,652	$58,250,992	($35,790,829)			
	Total	$21,467,430	$55,587,499	($33,431,002)	($22,617,637)	($10,813,365)	<0%
PENELEC	Counter Flow	($11,053,769)	($33,363,362)	$21,954,786			
	Prevailing Flow	$72,862,608	$103,902,070	($28,700,699)			
	Total	$61,808,839	$70,538,708	($6,745,913)	$58,884,119	($65,630,032)	<0%
Pepco	Counter Flow	$2,751,544	($17,578,229)	$20,418,092			
	Prevailing Flow	$108,481,057	$110,673,874	$1,289,236			
	Total	$111,232,601	$93,095,645	$21,707,328	$66,040,760	($44,333,432)	32.9%
PJM	Counter Flow	($7,409,025)	($10,469,858)	$2,823,017			
	Prevailing Flow	$2,474,268	$6,199,137	($3,645,449)			
	Total	($4,934,756)	($4,270,721)	($822,432)	$8,551,453	($9,373,885)	<0%
PPL	Counter Flow	($1,063,123)	($8,578,713)	$7,481,466			
	Prevailing Flow	$22,095,877	$69,681,584	($46,876,468)			
	Total	$21,032,754	$61,102,871	($39,395,002)	($8,203,127)	($31,191,875)	<0%
PSEG	Counter Flow	$607,455	($10,115,255)	$10,742,209			
	Prevailing Flow	$33,855,967	$123,238,031	($88,295,346)			
	Total	$34,463,423	$113,122,776	($77,553,137)	($1,140,092)	($76,413,045)	<0%
RECO	Counter Flow	($1,140,833)	($4,314,908)	$3,137,456			
	Prevailing Flow	($45,946)	$1,453,174	($1,500,595)			
	Total	($1,186,779)	($2,861,734)	$1,636,862	$1,562,712	$74,149	104.7%
Total	Counter Flow	($81,145,687)	($224,411,623)	$140,661,301			
	Prevailing Flow	$960,982,817	$1,573,678,643	($581,849,954)			
	Total	$879,837,129	$1,349,267,020	($441,188,653)	$816,996,461	($2,163,536,265)	<0%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-22 ARR and FTR congestion hedging by control zone: Planning period 2009 to 2010 (See 2009 SOM Table 8-27)

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$19,253,322	$4,219,286	$24,404,104	($931,496)	$11,668,534	($12,600,030)	<0%
AEP	$223,262,229	$157,902,719	$217,879,838	$163,285,110	$116,052,957	$47,232,153	>100%
AP	$365,048,488	$185,755,476	$329,392,239	$221,411,725	$127,452,651	$93,959,074	>100%
BGE	$52,131,739	$29,775,002	$36,152,570	$45,754,171	$38,375,399	$7,378,772	>100%
ComEd	$27,261,279	$61,695,532	$13,172,043	$75,784,768	$214,320,006	($138,535,238)	35.4%
DAY	$7,505,314	$1,208,727	$301,370	$8,412,671	$7,251,176	$1,161,495	>100%
DLCO	$2,454,337	$10,772,485	($3,168,727)	$16,395,549	$23,090,875	($6,695,326)	71.0%
Dominion	$213,840,239	$156,702,023	$233,943,347	$136,598,915	$144,663,009	($8,064,094)	94.4%
DPL	$17,792,090	$13,280,075	$35,171,391	($4,099,226)	$25,523,871	($29,623,097)	<0%
JCPL	$34,924,192	($889,982)	$43,756,129	($9,721,919)	$19,798,670	($29,520,589)	<0%
Met-Ed	$27,312,021	$15,466,636	$33,289,557	$9,489,100	$3,372,231	$6,116,869	>100%
PECO	$49,863,646	$21,465,214	$55,525,390	$15,803,470	($23,582,715)	$39,386,185	>100%
PENELEC	$49,412,326	$61,802,460	$69,940,862	$41,273,924	$52,397,326	($11,123,402)	78.8%
Pepco	$23,702,306	$111,221,120	$92,127,593	$42,795,833	$60,979,815	($18,183,982)	70.2%
PJM	$9,979,482	($4,934,247)	($4,320,705)	$9,365,940	($5,687,389)	$15,053,329	>100%
PPL	$55,143,860	$21,030,583	$61,139,754	$15,034,689	($9,016,274)	$24,050,963	>100%
PSEG	$94,609,270	$34,459,866	$112,939,182	$16,129,954	$3,593,597	$12,536,357	>100%
RECO	($41,455)	($1,186,657)	($2,841,361)	$1,613,249	$1,390,092	$223,157	>100%
Total	$1,273,454,685	$879,746,321	$1,348,804,576	$804,396,430	$811,643,831	($7,247,401)	99.1%

Table 8-23 ARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010 (See 2009 SOM Table 8-28)

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2008/2009	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,489,647,665	$130,237,257	>100%
2009/2010	$1,276,852,551	$879,858,494	$1,368,744,320	$787,966,725	$816,996,461	($29,029,736)	96.4%

ARRs and FTRs as a Hedge against Total Real Time Energy Charges

Table 8-24 ARRs and self-scheduled FTR credits as a hedge against energy charges by control zone: January through June 2010 (See 2009 SOM, Table 8-29)

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and Self-Scheduled FTR Credits
AECO	$7,219,021	$751,254	$7,970,276	$271,513,214	2.9%
AEP	$2,480,069	$98,203,487	$100,683,556	$2,624,894,987	3.8%
AP	$21,725,051	$161,824,339	$183,549,390	$1,038,462,004	17.7%
BGE	$21,684,973	$2,514,327	$24,199,300	$906,573,516	2.7%
ComEd	$12,784,592	$9,277,997	$22,062,589	$1,709,282,695	1.3%
DAY	$2,868,458	$1,042,618	$3,911,076	$329,224,754	1.2%
DLCO	$1,429,200	$488	$1,429,688	$280,788,853	0.5%
Dominion	$2,947,981	$123,382,623	$126,330,604	$2,545,936,995	5.0%
DPL	$7,722,753	$621,469	$8,344,222	$471,469,578	1.8%
JCPL	$12,947,621	$1,488,435	$14,436,056	$580,651,089	2.5%
Met-Ed	$1,135,955	$7,003,783	$8,139,737	$371,324,980	2.2%
PECO	$939,633	$15,901,854	$16,841,487	$1,011,524,525	1.7%
PENELEC	$11,448,978	$7,144,243	$18,593,221	$365,980,867	5.1%
Pepco	$10,717,044	$1,185,424	$11,902,469	$856,973,155	1.4%
PJM	$4,669,879	$1,603,965	$6,273,844	NA	NA
PPL	$2,120,206	$8,965,617	$11,085,823	$967,273,370	1.1%
PSEG	$37,871,812	$3,017,675	$40,889,487	$1,125,125,064	3.6%
RECO	($9,486)	$0	($9,486)	$36,400,979	(0.0%)
Total	$162,703,742	$443,929,599	$606,633,341	$15,519,070,251	3.9%

Table 8-25 FTRs as a hedge against energy charges by control zone: January through June 2010 (See 2009 SOM, Table 8-30)

Control Zone	FTR Credits (Excluding Self-Scheduled FTRs)	FTR Auction Revenue (Excluding Self-Scheduled FTRs)	Total FTR Hedge (Excluding Self-Scheduled FTRs)	Total Energy Charges	Percent of Energy Charges Covered by FTR Credits (Excluding Self-Scheduled FTRs)
AECO	$4,665,132	$8,540,145	($3,875,013)	$271,513,214	(1.4%)
AEP	$6,384,508	($1,298,303)	$7,682,812	$2,624,894,987	0.3%
AP	($5,056,742)	$86,557	($5,143,299)	$1,038,462,004	(0.5%)
BGE	$20,058,477	$15,606,242	$4,452,235	$906,573,516	0.5%
ComEd	$27,010,525	$6,220,467	$20,790,058	$1,709,282,695	1.2%
DAY	($377,899)	($512,603)	$134,704	$329,224,754	0.0%
DLCO	$12,291,134	($2,633,100)	$14,924,233	$280,788,853	5.3%
Dominion	$14,470,372	$10,671,051	$3,799,321	$2,545,936,995	0.1%
DPL	$8,859,853	$15,336,161	($6,476,308)	$471,469,578	(1.4%)
JCPL	$4,312,092	$17,663,388	($13,351,297)	$580,651,089	(2.3%)
Met-Ed	$6,070,972	$2,982,318	$3,088,655	$371,324,980	0.8%
PECO	$3,356,273	$3,675,675	($319,402)	$1,011,524,525	(0.0%)
PENELEC	$36,505,723	$23,640,178	$12,865,544	$365,980,867	3.5%
Pepco	$68,831,642	$51,625,849	$17,205,793	$856,973,155	2.0%
PJM	($3,460,897)	($3,954,214)	$493,317	NA	NA
PPL	$3,565,366	$4,294,064	($728,697)	$967,273,370	(0.1%)
PSEG	$35,613,845	$49,462,696	($13,848,851)	$1,125,125,064	(1.2%)
RECO	($759,509)	($1,357,902)	$598,393	$36,400,979	1.6%
Total	$242,340,867	$200,048,670	$42,292,198	$15,519,070,251	0.3%

Table 8-26 ARRs and FTRs as a hedge against energy charges by control zone: January through June 2010 (See 2009 SOM, Table 8-31)

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	$7,970,276	($3,875,013)	$4,095,263	$271,513,214	1.5%
AEP	$100,683,556	$7,682,812	$108,366,368	$2,624,894,987	4.1%
AP	$183,549,390	($5,143,299)	$178,406,091	$1,038,462,004	17.2%
BGE	$24,199,300	$4,452,235	$28,651,536	$906,573,516	3.2%
ComEd	$22,062,589	$20,790,058	$42,852,647	$1,709,282,695	2.5%
DAY	$3,911,076	$134,704	$4,045,780	$329,224,754	1.2%
DLCO	$1,429,688	$14,924,233	$16,353,921	$280,788,853	5.8%
Dominion	$126,330,604	$3,799,321	$130,129,925	$2,545,936,995	5.1%
DPL	$8,344,222	($6,476,308)	$1,867,914	$471,469,578	0.4%
JCPL	$14,436,056	($13,351,297)	$1,084,760	$580,651,089	0.2%
Met-Ed	$8,139,737	$3,088,655	$11,228,392	$371,324,980	3.0%
PECO	$16,841,487	($319,402)	$16,522,084	$1,011,524,525	1.6%
PENELEC	$18,593,221	$12,865,544	$31,458,765	$365,980,867	8.6%
Pepco	$11,902,469	$17,205,793	$29,108,262	$856,973,155	3.4%
PJM	$6,273,844	$493,317	$6,767,162	NA	NA
PPL	$11,085,823	($728,697)	$10,357,126	$967,273,370	1.1%
PSEG	$40,889,487	($13,848,851)	$27,040,636	$1,125,125,064	2.4%
RECO	($9,486)	$598,393	$588,907	$36,400,979	1.6%
Total	$606,633,341	$42,292,198	$648,925,539	$15,519,070,251	4.2%