Q3

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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2010

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 September*.

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

2 OATT Attachment M § II(f).

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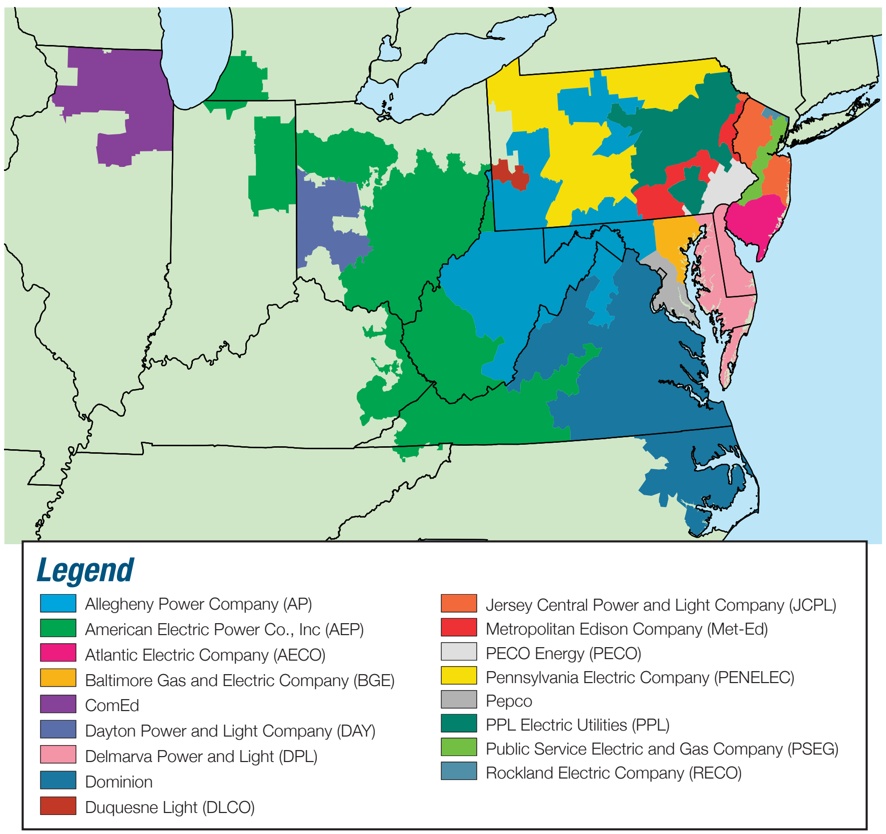
SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2010, had installed generating capacity of 166,732 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] Through the first nine months of 2010, PJM had total billings of $26.25 billion. 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 nine 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.

The MMU introduces a more refined scale for evaluating each PJM market in this quarterly report. The market structure is evaluated, the participant behavior is evaluated and the market performance is evaluated. The outcome of each market, market performance, is evaluated as competitive or not competitive.

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."

In addition, the MMU introduces an evaluation of market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report assesses the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

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

Participant behavior refers to the actions of individual market participants. Unit mark up is an important measure of participant behavior. Unit mark up measures the relationship between the offer of a unit and the marginal cost of a unit. The higher the unit mark up, the less competitive the offer.

Market performance refers to the outcome of the market. Market performance reflects the behavior of market participants within a market structure, mediated by market design. Mark up and net revenue are the most relevant measures of market performance. Mark up measures the relationship between the marginal costs of marginal units and the marginal offers of marginal units and therefore the market clearing prices in the market. The higher the performance mark up, the less competitive the market. Net revenue measures the revenues available from markets in excess of marginal costs, which are available to cover all other unit costs.

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

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

Table 1-1 The Energy Market results were competitive

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

Table 1-2 The Capacity Market results were competitive

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

Table 1-3 The Regulation Market results were not competitive[4]

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

Table 1-4 The Synchronized Reserve Markets results were competitive

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

4 As Table 1-3 indicates, 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, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

Table 1-5 The Day Ahead Scheduling Reserve Market results were competitive

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

Table 1-6 The FTR Auction Markets results were competitive

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

Role of MMU in Market Design Recommendations

The PJM Market Monitoring Plan provides under the heading "Monitoring of PJM Market Rules, PJM Tariff and 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 PJM Market Rules, PJM Tariff and design of the PJM Markets. The Market Monitoring Unit shall evaluate and monitor existing and proposed PJM Market Rules, PJM Tariff provisions, and the design of the PJM Markets. However, if the Market Monitoring Unit detects a design flaw or other problem with the PJM Markets, the Market Monitoring Unit shall not effectuate its proposed market design since that is the responsibility of the Office of the Interconnection. The Market Monitoring Unit may initiate and propose, through the appropriate stakeholder processes, changes to the design of such markets, as well as changes to the PJM Market Rules and PJM Tariff. 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. The Market Monitoring Unit may also recommend changes to the PJM Market Rules and PJM Tariff provisions to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[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 September*, 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 June* are still valid, and the MMU makes the following new recommendations.

- The MMU recommends that the December 1, 2008, 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 MMU also recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected. This change would maintain transparent incentives consistent with an effective market design. In the longer run, the proposed modifications to the pricing of regulation by both PJM and the MMU in their scarcity pricing recommendations will result in revenue increases that are expected to exceed any revenue loss from correcting the opportunity cost calculation.[7] The MMU recommends that when the scarcity related modifications are implemented, the margin be reduced to its current level.

- The MMU recommends that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion

5 PJM OATT Attachment M § IV.D.
6 PJM OATT Attachment M § VI.A.
7 *See, e.g.*, PJM compliance filing in Docket No. ER09-1063-004 (June 18, 2010); Protest and Compliance Proposal of the Independent Market Monitor for PJM, Docket No. ER09-1063-004, (July 19, 2010).

charges. The MMU recommends charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service.

- The MMU recommends limiting the use of not willing to pay congestion transactions to wheeling transactions only. It is not possible to control the flow of energy from an external interface to an internal bus within the PJM footprint. 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.

Highlights and New Analysis

The MMU has enhanced this *2010 Quarterly State of the Market Report for PJM: January through September* with the following new analysis since the prior quarterly report:

Section 1, "Introduction"

- Conclusions regarding the competitiveness of each market. (Pages 2, 3)
- New recommendations. (Pages 3, 4)

Section 2, "Energy Market, Part 1"

- Average offered supply increased slightly over Q2, and over Q3 in 2009. (Page 7)
- Peak and average load, and day-ahead and real-time prices increased over Q2, and over Q3 in 2009. (Page 8)
- New analysis: History of locational marginal prices (LMPs) comparing year to date prices to comparable period in prior year. (Table 2-59, Page 40)
- New analysis: Settled Demand-Side Response volume was approximately the same compared to the same period in 2009, while credits were significantly higher in 2010 due to higher price levels. (Page 10)
- New analysis: Preliminary review of Load Management emergency event compliance for the 2010 summer period. (Page 10)

Section 3, "Energy Market, Part 2"

- Net revenues increased from Q3 in 2009. (Page 73)
- Operating reserve charges increased from Q3 in 2009. (Page 74)
- New analysis: New entrant net revenue by market types for combustion turbine, combined cycle, and coal plant unit types, in Figures 3-1, 3-3, and 3-5. (Pages 83, 85, 86)

Section 4, "Interchange Transactions"

- Day-ahead and real-time net exports increased in Q3 over Q2, and over Q3 in 2009. (Page 109)
- New analysis: Summary of marginal loss surplus allocation analysis. (Page 114)
- Enhanced analysis of "not willing to pay congestion" transactions. (Page 115)

Section 5, "Capacity Markets"

- RTO capacity prices for cleared resources in the 2010/2011 RPM Base Residual Auction are increased from the 2009/2010 BRA, and prices for the 2010/2011 Third Incremental Auction are increased from the 2009/2010 Third Incremental Auction. (Table 5-10, Page 151)
- Forced Outage (EFORd) values decreased in Q3 from the corresponding values in Q3 2009. (Page 140)
- New analysis: The results of the RPM 2012/2013 First Incremental Auction are reported. (Page 139)

Section 6, "Ancillary Service Markets"

- Regulation prices increased from Q2 slightly, but remain lower than in 2009. (Page 163)
- Synchronized reserve prices were higher in Q3 than in Q2, and remain higher than in 2009. (Page 165)
- New analysis: History of PJM regulation and spinning market prices. (Table 6-8 and Table 6-13, Pages 170 and 176)

Section 7, "Congestion"

- Congestion costs in Q3 were higher than in Q2, and significantly higher than in Q3 2009. (Page 180)

- New analysis: Review of FERC decisions regarding restructuring responsibility for grid development. (Page 178)

Section 8, "Financial Transmission and Auction Revenue Rights"

- Prices in the Monthly Balance of Planning Period FTR Auctions were down from Q2, and were lower than in Q3 of 2009. (Page 228)

- New analysis: Summary of Tower litigation. (Page 228)

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 1-7 provides the average price and total revenues paid, by component for calendar year 2009 and for January through September 2010.

Table 1-7 shows that Energy, Capacity and Transmission Service Charges represent the three largest components of the total price per MWh of wholesale power, contributing 96.7 percent of the total price per MWh for the January through September 2010 period. Of these components, the cost of energy was the most important, making up 73.6 percent of the total price per MWh for the January through September 2010 period, while the cost of capacity contributed 17.3 percent and the cost of transmission service contributed 5.8 percent of the total price per MWh for the January through September 2010 period.

The total per MWh price of wholesale power for the January through September 2010 period, $67.81, was 22.0 percent higher than total per MWh price of wholesale power for the 2009 calendar year, $55.58. This increase in the total per MWh price is largely attributable to the 27.8 percent increase in the price of energy.

The total per MWh price of Energy for the January through September 2010 period, $49.91, was 26.2 percent higher than for the comparable period in 2009, $39.57. The total per MWh price of Capacity for the January through September period, $11.71, was 29.9 percent higher than for the comparable period in 2009, $9.01. The total per MWh price of Transmission Service for the January through September period, $3.93, was 11.1 percent higher than for the comparable period in 2009, $3.54.

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 nine 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.[8]

- The Operating Reserve (Uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[9]

- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[10]

- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[11]

- 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

8 PJM OATT §§ 13.7, 14.5, 27A & 34.
9 PJM Operating Agreement Schedules 1 §§ 3.2.3 & 3.3.3.
10 PJM OATT Schedule 2 and Operating Agreement Schedule 1 § 3.2.3B.
11 PJM Operating Agreement Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; PJM OATT Schedule 3.

through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAILCo and PATH projects.[12]

- 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.[13]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[14]
- The Black Start component is the average cost per MWh of black start service.[15]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[16]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[17]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[18]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[19]

Table 1-7 Total price per MWh by Category and Total Revenues by Category: January through December 2009 and January through September 2010 (See 2009 SOM, Table 1-1)

Category	Totals ($ Millions) Jan-Dec 2009	Totals ($ Millions) Jan-Sep 2010	Jan-Dec 2009 $/MWh	Jan-Sep 2010 $/MWh	Jan-Dec 2009 Percent	Jan-Sep 2010 Percent
Energy	$26,008.22	$26,508.11	$39.05	$49.91	70.2%	73.6%
Capacity	$7,162.71	$6,220.22	$10.75	$11.71	19.3%	17.3%
Transmission Service Charges	$2,664.73	$2,088.31	$4.00	$3.93	7.2%	5.8%
Operating Reserves (Uplift)	$324.15	$406.88	$0.49	$0.77	0.9%	1.1%
Regulation	$203.49	$199.13	$0.31	$0.37	0.5%	0.6%
PJM Administrative Fees	$242.32	$199.05	$0.36	$0.37	0.7%	0.6%
Reactive	$228.18	$189.47	$0.34	$0.36	0.6%	0.5%
Transmission Enhancement Cost Recovery	$63.21	$90.76	$0.09	$0.17	0.2%	0.3%
Transmssion Owner (Schedule 1A)	$56.47	$47.09	$0.08	$0.09	0.2%	0.1%
Synchronized Reserves	$34.27	$31.30	$0.05	$0.06	0.1%	0.1%
NERC/RFC	$8.86	$10.70	$0.01	$0.02	0.0%	0.0%
Black Start	$14.27	$8.40	$0.02	$0.02	0.0%	0.0%
RTO Startup and Expansion	$9.12	$6.84	$0.01	$0.01	0.0%	0.0%
Load Response	$1.62	$3.79	$0.00	$0.01	0.0%	0.0%
Transmission Facility Charges	$1.39	$1.02	$0.00	$0.00	0.0%	0.0%
Total	$37,023.01	$36,011.07	$55.58	$67.81	100.0%	100.0%

12 PJM OATT Schedule 12.
13 PJM OATT Schedule 1A.
14 PJM Operating Agreement Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
15 PJM OATT Schedule 6A.
16 PJM OATT Attachments H-13, H-14 and H-15 and Schedule 13.
17 PJM OATT Schedule 10-NERC and OATT Schedule 10-RFC.
18 PJM Operating Agreement Schedule 1 § 3.6.
19 PJM Operating Agreement Schedule 1 § 5.3b.

SECTION 2 – ENERGY MARKET, PART 1

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for January through September of 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 nine 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 third quarter of 2010, the PJM Energy Market received an hourly average of 155,322 MWh in supply offers including hydroelectric generation.[3] The third quarter 2010 average daily offered supply was 1,624 MWh higher than the third quarter 2009 average daily offered supply of 153,698 MWh.

- **Demand.** The PJM system peak load for the third quarter 2010 was 136,460 MW in the hour ended 1600 EPT on July 6, 2010, while the PJM peak load for the third quarter 2009 was 126,798 MW in the hour ended 1600 EPT on August 10, 2009.[4] The third quarter 2010 peak load was 9,662 MW, or 7.6 percent, higher than the third 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 September*, 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 nine months of 2010. In the Real-Time Energy Market offer-capped unit hours increased from 0.4 percent in 2009 to 1.2 percent in the period from January through September 2010.

On June 9, 2010, PJM replaced the Look-Ahead Unit Dispatch Software (LA UDS) with new short run look ahead Security Constrained Economic Dispatch (SCED 2; or IT SCED) optimization software. The three pivotal supplier test (TPS) is now run in SCED 2. 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.

- **Local Market Structure.** For the period July 1, 2010 through September 30, 2010, a summary of the TPS results based on SCED is presented for all constraints which occurred for 25 or more hours.

  During July, August and September of 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 25 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 nine months of 2010 was $0.49 per MWh, or 1.0 percent. Coal steam units contributed -$1.14 to the total markup component of LMP. Combustion turbine units that use natural gas as their primary fuel source contributed $0.41 to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.97 to the total markup component of LMP. The markup was $2.04 per MWh during peak hours and -$1.18 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP for the first nine months of 2010 was -$0.60 per MWh, or -1.2 percent. Coal steam units contributed -$0.72 to the total markup component of LMP. Natural gas steam units contributed $0.09 to the total markup component of LMP. The markup was $0.04 per MWh during peak hours and -$1.29 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 nine months of 2010 by 5.3 percent from the first nine months of 2009, rising from 76,956 MW to 81,068 MW. PJM day-ahead load increased in the first nine months of 2010 by 3.3 percent from the first nine months of 2009, rising from 89,680 MW to 92,683 MW.

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

PJM Real-Time Energy Market prices increased in the first nine months of 2010 compared to the first nine months of 2009. The system simple average LMP was 23.3 percent higher in the first nine months of 2010 than in the first nine months of 2009, $46.13 per MWh versus $37.42 per MWh. The load-weighted LMP was 26.2 percent higher in the first nine months of 2010 than the first nine months of 2009, $49.91 per MWh versus $39.57 per MWh. The real-time, fuel cost adjusted, load-weighted, average LMP[5] was 25.7 percent higher for the first nine months of 2010 than the load-weighted, average LMP for the first nine months of 2009, $49.74 per MWh versus $39.57 per MWh. In other words, if fuel costs in the first nine months of 2010 were the same as they had been in the first nine months of 2009, the 2010 load-weighted LMP would have been 0.3 percent lower, $49.74 per MWh, than the actual $49.91 per MWh, and 25.7 percent higher than the load-weighted average LMP for the first nine months of 2009. Higher loads and fuel costs contributed to upward pressure on LMP in the first nine months of 2010.

PJM Day-Ahead Energy Market prices increased in the first nine months of 2010 compared to the first nine months of 2009. The system simple average LMP was 22.7 percent higher in the first nine months of 2010 than in the first nine months of 2009, $45.81 per MWh versus $37.35 per MWh. The load-weighted LMP was 24.8 percent higher in the first nine months of 2010 than in the first nine months of 2009, $49.12 per MWh versus $39.35 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 nine months of 2010, 11.5 percent of real-time load was supplied by bilateral contracts, 19.4 percent by spot market purchases and 69.1 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 1.3 percentage points; reliance on spot supply increased by 2.4 percentage points; and reliance on self-supply decreased by 1.0 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 nine months of 2010, in the Economic Program, participation was more concentrated compared to the first nine months of 2009. Settled MWh were approximately the same compared to the same period in 2009, while credits were significantly higher in 2010 due to higher price levels. However, there were generally fewer settlements submitted, fewer registered customers, and fewer active customers compared to the same period in 2009. Participation levels through calendar year 2009 and through the first three months of 2010 were generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification, but have showed strong growth through the second and third quarter as price levels and load levels have increased. On the peak load day for the period January through September 2010 (July 6, 2010), there were 1,725.7 MW registered in the Economic Load Response Program.

5 The MMU's fuel cost adjusted LMP analysis reflects both fuel and emission cost differences over the periods in question. It could also be characterized as input cost adjusted LMP analysis.

In the first nine months of 2010, the Emergency Program, specifically, the Load Management (LM) Program, participation increased compared to the same period in 2009.[6] 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 8,875.9 MW registered in the LM Program, compared to 7,294.3 MW registered in the 2009/2010 delivery year.

There were six PJM Load Management Events declared in 2010, five were within the summer compliance period (June 1 through September 30) and one was declared before the summer period on May 26. Both the May 26 and the June 11 events were called for the District of Columbia (DC) portions of Pepco. The June 11 event marks the first time that PJM called a load management event at a sub-zonal level within the compliance period. Prior to this point, load management events and thus compliance were aggregated to a zonal basis. While all PJM Emergency Actions, including Load Management Events, may be issued for part of a zone, the only locational requirement for the aggregation of multiple end use customers to a single registration is that they reside in the same control zone. Similarly, compliance for testing and for zonal Emergency Events, is aggregated for each Curtailment Service Provider (CSP) to a zonal basis. Some market participants were not prepared to deploy resources at a sub-zonal level, and they submitted compliance data for all resources located in Pepco. Preliminary results for the June 11 event show that resources within the DC portion of Pepco zone accounted for load reductions in excess of 90 percent of total nominated ICAP.

If reductions for outside the DC portion of Pepco were to be included for event compliance, yet compliance was determined only considering commitments within the DC portion of Pepco, then the level of compliance derived, in excess of 200 percent, would be overstated and meaningless, as it would measure compliance by comparing load reductions from participants outside the affected area, which do not affect the level of required load reductions in the subzone, to the level of commitments inside the subzone.[7] However, if compliance is calculated for all resources within Pepco for which data were submitted, taking into account both reductions and nominal commitments from outside the DC portion of Pepco, compliance is significantly less than nominated commitments, below 70 percent. While it may be reasonable to consider a broader geographical area as one element of evaluating compliance, it is not logical to compare reductions from outside the DC portion of Pepco to commitments inside the DC portion of Pepco. Regardless of the geographical scope, any compliance calculation should reflect the nominated commitment of any resource for which a reduction is considered. That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are assessed compliance on a zonal basis, represents a broader issue that needs to be addressed. More precise locational deployment of Load Management leads to system efficiencies, however, it reduces the ability of a CSP to aggregate customers and spread risk over a geographical area within a zone.

Preliminary results for the July 7 event for EMAAC, SWMAAC and Dominion zones show load reductions greater than 90 percent of total nominated ICAP.[8] The proportion of customers meeting nominated commitments is substantially lower for both events, less than 50 percent, which implies significant over compliance from a subset of larger customers. Further, the MMU has raised concerns with PJM and stakeholders on the measurement and verification protocols in place to quantify load reductions for the 2010/2011 delivery year and these methods will be under review in calendar year 2011.

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 nine months of 2010. In the first nine months of 2010, payments from the Economic Program increased from the first nine months of 2009 by $948,000 or 82 percent, from $1.2 Million to $2.1 Million while capacity revenue increased from the first nine months of 2009 by $154 million or 74 percent, from $208 million to $362 million since 2009.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the first nine months of 2010, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation

6 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.

7 This appears to be the level of compliance shown for the June 11 event in the preliminary compliance report released by PJM. See: http://www.pjm.com/~/media/markets-ops/dsr/emergency-load-management-events-2010-preliminary-summary.ashx

8 Compliance figures are preliminary and are based on registered nominal reductions which do not consider replacement capacity transactions. Complete data for the September events are not yet available.

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 hourly supply offered increased by about 1,624 MWh when comparing the third quarter of 2010 to the third quarter of 2009, while aggregate peak load increased by 9,662 MW, modifying the general supply demand balance from the third quarter of 2009 with a corresponding impact on Energy Market prices. Average load in the first nine months of 2010 also increased from the first nine months of 2009, rising from 76,956 MW to 81,068 MW. Market concentration levels remained moderate and average markup was slightly positive. This relationship between supply and demand, regardless of the specific market, balanced by market concentration and residual supplier levels, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

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.[9] 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 nine months of 2010 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher demand and higher fuel costs. PJM Real-Time, load-weighted, average LMP for the first nine months of 2010 was $49.91, or 26.2 percent higher than the load-weighted, average LMP for the first nine months of 2009, which was $39.57. The real-time fuel cost adjusted, load-weighted, average LMP was 25.7 percent higher for the first nine months of 2010 than the load-weighted, average LMP in for the first nine months of 2009, $49.74 per MWh compared to $39.57 per MWh. In other words, if fuel costs in the first nine months of 2010 were the same as they had been in the first nine months of 2009, the 2010 load-weighted LMP would have been 0.3 percent lower, $49.74 per MWh, than the actual $49.91 per MWh, and 25.7 percent higher than the load-weighted average LMP for the first nine months of 2009. Higher loads and fuel costs contributed to upward pressure on LMP in the first nine months of 2010.

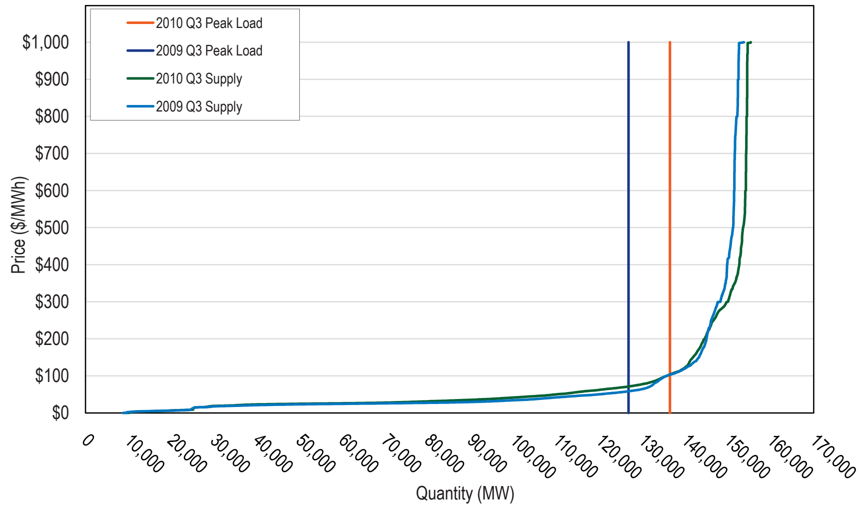
The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change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

9 See *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶61,321 (1997); FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶61,157 (2008).

Market Structure

Supply

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



Demand

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

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)	Difference (%)
2003	Fri, August 22	15	61,499	NA	NA
2004	Tue, August 03	16	77,887	16,387	26.6%
2005	Tue, July 26	15	133,761	55,875	71.7%
2006	Wed, August 02	16	144,644	10,883	8.1%
2007	Wed, August 08	15	139,428	(5,216)	(3.6%)
2008	Thu, July 17	16	129,481	(9,947)	(7.1%)
2009	Mon, August 10	16	126,798	(2,683)	(2.1%)
2010	Tue, July 06	16	136,460	9,662	7.6%

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

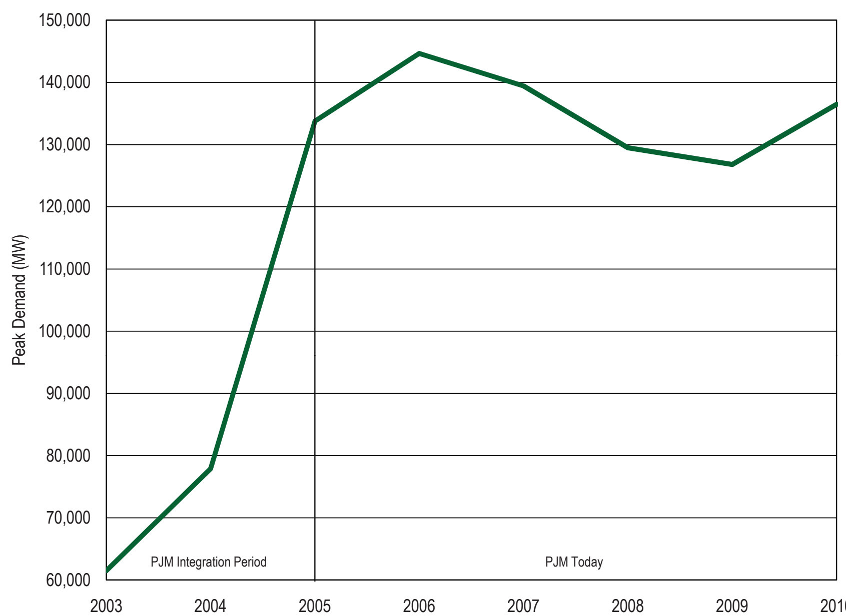
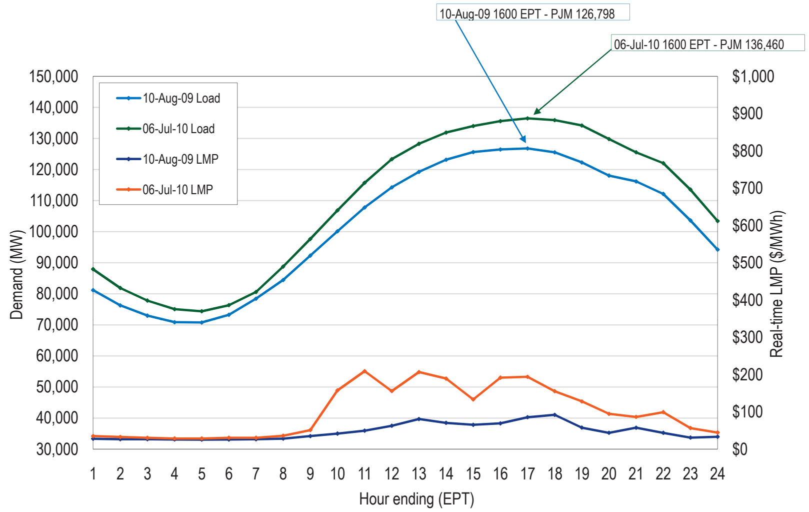


Figure 2-3 PJM third quarter peak-load comparison: Tuesday, July 06, 2010 and Monday, August 10, 2009 (See 2009 SOM, Figure 2-3)



Market Concentration

PJM HHI Results[10]

Table 2-2 PJM hourly Energy Market HHI: January through September 2010[11] (See 2009 SOM, Table 2-2)

	Hourly Market HHI
Average	1180
Minimum	914
Maximum	1599
Highest market share (One hour)	31%
Highest market share (All hours)	20%
# Hours	6,551
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

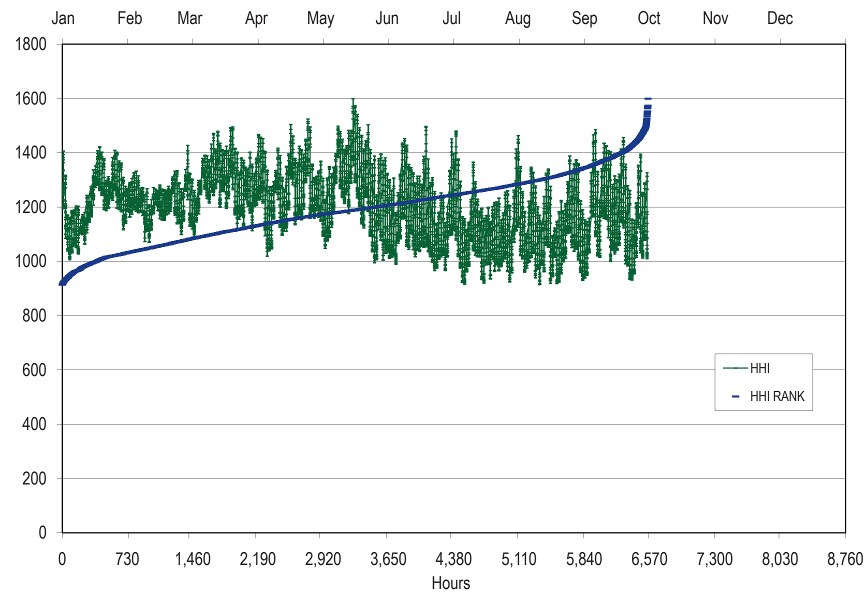
10 HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest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

11 This analysis includes all hours of the first nine months of 2010, regardless of congestion.

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

	Minimum	Average	Maximum
Base	1070	1241	1550
Intermediate	681	1747	7279
Peak	606	6160	10000

Figure 2-4 PJM hourly Energy Market HHI: January through September 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 September 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	1.2%	0.3%	0.3%	0.1%

Table 2-5 Real-time offer-capped unit statistics: January through September 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%	2	1	0	0	2	15
80% and < 90%	1	0	1	6	8	17
75% and < 80%	0	0	0	0	0	6
70% and < 75%	1	0	0	0	4	11
60% and < 70%	0	0	3	0	3	36
50% and < 60%	0	0	0	3	1	17
25% and < 50%	2	0	1	1	19	48
10% and < 25%	1	1	0	1	8	36

Local Market Structure[12]

Table 2-6 Three pivotal supplier results summary for regional constraints: July 1, 2010 through September 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	4,280	513	12%	4,077	95%
	Off Peak	1,299	203	16%	1,205	93%
AP South	Peak	4,711	135	3%	4,660	99%
	Off Peak	1,920	50	3%	1,899	99%
Bedington - Black Oak	Peak	8	1	13%	7	88%
	Off Peak	62	29	47%	50	81%
Central	Peak	40	8	20%	36	90%
	Off Peak	45	13	29%	35	78%
Doubs - Mount Storm	Peak	848	17	2%	837	99%
	Off Peak	674	5	1%	672	100%
East	Peak	4	2	50%	3	75%
	Off Peak	NA	NA	NA	NA	NA
Harrison - Pruntytown	Peak	3,188	302	9%	3,041	95%
	Off Peak	2,960	133	4%	2,889	98%
West	Peak	189	47	25%	167	88%
	Off Peak	NA	NA	NA	NA	NA

12 Effective June 9, 2010, 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, through September 30, 2010, the MMU is reporting SCED 2 based TPS results for regional 500 kV constraints.

Table 2-7 Three pivotal supplier results details for regional constraints: July 1, 2010 through September 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	368	2,178	18	2	16
	Off Peak	304	1,719	15	2	13
AP South	Peak	297	900	8	0	8
	Off Peak	382	793	7	0	7
Bedington - Black Oak	Peak	189	299	8	1	8
	Off Peak	148	1,211	9	3	6
Central	Peak	633	4,058	20	4	16
	Off Peak	574	3,228	15	5	10
Doubs - Mount Storm	Peak	195	1,170	15	0	15
	Off Peak	321	1,430	16	0	16
East	Peak	389	2,969	17	9	8
	Off Peak	NA	NA	NA	NA	NA
Harrison - Pruntytown	Peak	431	1,941	16	1	15
	Off Peak	484	2,020	15	1	15
West	Peak	707	4,455	19	4	14
	Off Peak	NA	NA	NA	NA	NA

Table 2-8 Three pivotal supplier test summary for constraints located in the AECO Control Zone: July 1, 2010 through September 30, 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
Monroe	Peak	1,134	0	0%	1,134	100%
	Off Peak	46	0	0%	46	100%
Shieldalloy - Vineland	Peak	1,737	0	0%	1,737	100%
	Off Peak	1,914	0	0%	1,914	100%

Table 2-9 Three pivotal supplier test details for constraints located in the AECO Control Zone: July 1, 2010 through September 30, 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
Monroe	Peak	7	6	2	0	2
	Off Peak	8	7	2	0	2
Shieldalloy - Vineland	Peak	12	13	2	0	2
	Off Peak	10	11	1	0	1

Table 2-10 Three pivotal supplier results summary for constraints located in the AEP Control Zone: July 1, 2010 through September 30, 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
Brues - West Bellaire	Peak	303	0	0%	303	100%
	Off Peak	767	0	0%	767	100%
Carnegie - Tidd	Peak	2,146	0	0%	2,146	100%
	Off Peak	342	0	0%	342	100%
Cloverdale	Peak	776	72	9%	759	98%
	Off Peak	2,717	57	2%	2,707	100%
Cloverdale - Ivy Hill	Peak	434	0	0%	434	100%
	Off Peak	310	0	0%	310	100%
Cloverdale - Lexington	Peak	1,682	308	18%	1,555	92%
	Off Peak	8,064	591	7%	7,971	99%
Dumont - Stillwell	Peak	147	16	11%	136	93%
	Off Peak	1,526	73	5%	1,470	96%
Kammer - Natrium	Peak	336	0	0%	336	100%
	Off Peak	371	0	0%	371	100%
Mahans Lane - Tidd	Peak	1,277	0	0%	1,277	100%
	Off Peak	922	0	0%	922	100%
Poston - Postel Tap	Peak	1,715	0	0%	1,715	100%
	Off Peak	286	0	0%	286	100%
Ruth - Turner	Peak	52	0	0%	52	100%
	Off Peak	683	0	0%	683	100%

Table 2-11 Three pivotal supplier test details for constraints located in the AEP Control Zone: July 1, 2010 through September 30, 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
Brues - West Bellaire	Peak	9	12	1	0	1
	Off Peak	18	21	1	0	1
Carnegie - Tidd	Peak	29	28	1	0	1
	Off Peak	46	20	1	0	1
Cloverdale	Peak	183	1,163	11	1	10
	Off Peak	193	1,266	8	0	8
Cloverdale - Ivy Hill	Peak	3	3	1	0	1
	Off Peak	4	3	1	0	1
Cloverdale - Lexington	Peak	184	1,830	16	2	14
	Off Peak	192	1,811	12	1	11
Dumont - Stillwell	Peak	252	1,961	21	2	19
	Off Peak	214	1,490	15	1	14
Kammer - Natrium	Peak	11	9	1	0	1
	Off Peak	13	17	1	0	1
Mahans Lane - Tidd	Peak	14	20	1	0	1
	Off Peak	13	20	1	0	1
Poston - Postel Tap	Peak	13	39	1	0	1
	Off Peak	4	20	1	0	1
Ruth - Turner	Peak	3	4	1	0	1
	Off Peak	12	6	1	0	1

Table 2-12 Three pivotal supplier results summary for constraints located in the AP Control Zone: July 1, 2010 through September 30, 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
Armstrong - Burma	Peak	268	0	0%	268	100%
	Off Peak	104	0	0%	104	100%
Bedington - Harmony	Peak	1,160	0	0%	1,160	100%
	Off Peak	388	0	0%	388	100%
Bedington - Shepherdstown	Peak	622	0	0%	622	100%
	Off Peak	60	0	0%	60	100%
Belmont	Peak	1,379	0	0%	1,379	100%
	Off Peak	494	0	0%	494	100%
Butler - Karns City	Peak	166	0	0%	166	100%
	Off Peak	843	0	0%	843	100%
Doubs	Peak	3,402	1	0%	3,402	100%
	Off Peak	401	0	0%	401	100%
Elrama - Mitchell	Peak	1,806	5	0%	1,805	100%
	Off Peak	6,658	5	0%	6,657	100%
Kingwood - Pruntytown	Peak	277	0	0%	277	100%
	Off Peak	251	0	0%	251	100%
Millvile - Sleepy Hollow	Peak	6,118	0	0%	6,118	100%
	Off Peak	1,754	0	0%	1,754	100%
Millville - Old Chapel	Peak	2,575	0	0%	2,575	100%
	Off Peak	1,276	0	0%	1,276	100%
Mount Storm - Pruntytown	Peak	5,901	659	11%	5,695	97%
	Off Peak	9,016	441	5%	8,909	99%
Muskingum River - East Newcon	Peak	426	0	0%	426	100%
	Off Peak	NA	NA	NA	NA	NA
Tiltonsville - Windsor	Peak	1,363	0	0%	1,363	100%
	Off Peak	528	0	0%	528	100%
Wylie Ridge	Peak	4,218	519	12%	3,947	94%
	Off Peak	8,826	723	8%	8,544	97%

Table 2-13 Three pivotal supplier test details for constraints located in the AP Control Zone: July 1, 2010 through September 30, 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
Armstrong - Burma	Peak	15	31	1	0	1
	Off Peak	9	13	2	0	2
Bedington - Harmony	Peak	17	9	2	0	2
	Off Peak	18	10	2	0	2
Bedington - Shepherdstown	Peak	26	4	1	0	1
	Off Peak	15	5	1	0	1
Belmont	Peak	18	24	1	0	1
	Off Peak	11	13	2	0	2
Butler - Karns City	Peak	6	10	2	0	2
	Off Peak	14	14	1	0	1
Doubs	Peak	14	17	3	0	3
	Off Peak	12	5	2	0	2
Elrama - Mitchell	Peak	64	76	3	0	3
	Off Peak	97	99	3	0	3
Kingwood - Pruntytown	Peak	6	3	1	0	1
	Off Peak	10	4	1	0	1
Millvile - Sleepy Hollow	Peak	41	21	2	0	2
	Off Peak	24	9	1	0	1
Millville - Old Chapel	Peak	43	17	2	0	2
	Off Peak	53	7	1	0	1
Mount Storm - Pruntytown	Peak	329	1,446	10	1	9
	Off Peak	343	1,427	9	0	8
Muskingum River - East Newcon	Peak	6	8	1	0	1
	Off Peak	NA	NA	NA	NA	NA
Tiltonsville - Windsor	Peak	16	11	1	0	1
	Off Peak	20	15	1	0	1
Wylie Ridge	Peak	184	1,036	18	2	16
	Off Peak	189	922	13	1	13

Table 2-14 Three pivotal supplier results summary for constraints located in the BGE Control Zone: July 1, 2010 through September 30, 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	2,038	213	10%	1,928	95%
	Off Peak	411	67	16%	380	92%
Graceton - Safe Harbor	Peak	NA	NA	NA	NA	NA
	Off Peak	566	381	67%	258	46%

Table 2-15 Three pivotal supplier test details for constraints located in the BGE Control Zone: July 1, 2010 through September 30, 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	64	370	12	1	10
	Off Peak	53	362	10	1	9
Graceton - Safe Harbor	Peak	NA	NA	NA	NA	NA
	Off Peak	53	737	12	9	2

Table 2-16 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: July 1, 2010 through September 30, 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 - Sheffield	Peak	907	0	0%	907	100%
	Off Peak	665	0	0%	665	100%
Cherry Valley	Peak	782	0	0%	782	100%
	Off Peak	35	0	0%	35	100%
East Frankfort - Crete	Peak	1,346	7	1%	1,342	100%
	Off Peak	4,190	33	1%	4,166	99%
Electric Jct - Nelson	Peak	1,281	3	0%	1,280	100%
	Off Peak	985	0	0%	985	100%
Nelson - Cordova	Peak	1,098	18	2%	1,089	99%
	Off Peak	290	0	0%	290	100%
Pleasant Valley - Belvidere	Peak	616	0	0%	616	100%
	Off Peak	1131	0	0%	1131	100%
Waterman - West Dekalb	Peak	220	0	0%	220	100%
	Off Peak	622	0	0%	622	100%
Wayne - 7910	Peak	377	0	0%	377	100%
	Off Peak	177	0	0%	177	100%
Wayne - 7915	Peak	1,285	0	0%	1,285	100%
	Off Peak	123	0	0%	123	100%

Table 2-17 Three pivotal supplier test details for constraints located in the ComEd Control Zone: July 1, 2010 through September 30, 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 - Sheffield	Peak	117	1,403	2	0	2
	Off Peak	187	1,383	3	0	3
Cherry Valley	Peak	5	7	1	0	1
	Off Peak	1	2	1	0	1
East Frankfort - Crete	Peak	114	931	3	0	3
	Off Peak	115	1,101	3	0	3
Electric Jct - Nelson	Peak	42	28	3	0	3
	Off Peak	15	9	2	0	2
Nelson - Cordova	Peak	51	294	5	0	5
	Off Peak	39	152	2	0	2
Pleasant Valley - Belvidere	Peak	13	5	2	0	2
	Off Peak	3	2	1	0	1
Waterman - West Dekalb	Peak	6	17	1	0	1
	Off Peak	6	25	1	0	1
Wayne - 7910	Peak	19	24	1	0	1
	Off Peak	1	7	1	0	1
Wayne - 7915	Peak	29	33	1	0	1
	Off Peak	18	19	1	0	1

Table 2-18 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: July 1, 2010 through September 30, 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
Arsenal - Oakland	Peak	1,407	0	0%	1,407	100%
	Off Peak	156	0	0%	156	100%

Table 2-19 Three pivotal supplier test details for constraints located in the DLCO Control Zone: July 1, 2010 through September 30, 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
Arsenal - Oakland	Peak	39	45	2	0	2
	Off Peak	20	28	2	0	2

Table 2-20 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: July 1, 2010 through September 30, 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	4,452	0	0%	4,452	100%
	Off Peak	740	0	0%	740	100%
Benning - Ritchie	Peak	995	0	0%	995	100%
	Off Peak	1	0	0%	1	100%
Chaparral - Locks	Peak	678	3	0%	678	100%
	Off Peak	443	2	0%	443	100%
Clover	Peak	5,664	9	0%	5,659	100%
	Off Peak	972	2	0%	972	100%
Danville - East Danville	Peak	504	0	0%	504	100%
	Off Peak	1,309	0	0%	1,309	100%
Dooms	Peak	857	0	0%	857	100%
	Off Peak	95	0	0%	95	100%
Five Forks - Rock Ridge	Peak	711	0	0%	711	100%
	Off Peak	646	0	0%	646	100%
Halifax - Mount Laurel	Peak	1,301	0	0%	1,301	100%
	Off Peak	179	0	0%	179	100%

Table 2-21 Three pivotal supplier test details for constraints located in the Dominion Control Zone: July 1, 2010 through September 30, 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	9	37	1	0	1
	Off Peak	9	31	1	0	1
Benning - Ritchie	Peak	18	50	1	0	1
	Off Peak	10	61	1	0	1
Chaparral - Locks	Peak	93	327	4	0	4
	Off Peak	78	371	4	0	4
Clover	Peak	86	256	3	0	3
	Off Peak	101	242	3	0	3
Danville - East Danville	Peak	40	31	2	0	2
	Off Peak	58	45	2	0	2
Dooms	Peak	79	194	2	0	2
	Off Peak	86	160	2	0	2
Five Forks - Rock Ridge	Peak	17	13	1	0	1
	Off Peak	16	11	1	0	1
Halifax - Mount Laurel	Peak	8	10	1	0	1
	Off Peak	6	7	1	0	1

Table 2-22 Three pivotal supplier results summary for constraints located in the DPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

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
Edgemoor At20	Peak	266	0	0%	266	100%
	Off Peak	784	0	0%	784	100%
Greenbush - Hallwood	Peak	491	0	0%	491	100%
	Off Peak	606	0	0%	606	100%
Kenney - Stockton	Peak	2,492	0	0%	2,492	100%
	Off Peak	418	0	0%	418	100%

Table 2-23 Three pivotal supplier test details for constraints located in the DPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Edgemoor At20	Peak	222	282	2	0	2
	Off Peak	31	38	2	0	2
Greenbush - Hallwood	Peak	4	5	1	0	1
	Off Peak	9	9	1	0	1
Kenney - Stockton	Peak	32	35	1	0	1
	Off Peak	12	12	1	0	1

Table 2-24 Three pivotal supplier results summary for constraints located in the JCPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

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
Redoak - Sayreville	Peak	1,572	14	1%	1,570	100%
	Off Peak	51	0	0%	51	100%

Table 2-25 Three pivotal supplier test details for constraints located in the JCPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Redoak - Sayreville	Peak	48	100	4	0	4
	Off Peak	16	25	2	0	2

Table 2-26 Three pivotal supplier results summary for constraints located in the Met-Ed Control Zone: July 1, 2010 through September 30, 2010 (New Table)

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
Brunner Island - Yorkana	Peak	4,607	693	15%	4,315	94%
	Off Peak	1,371	19	1%	1,357	99%
Jackson - TMI	Peak	1,660	238	14%	1,525	92%
	Off Peak	195	24	12%	180	92%

Table 2-27 Three pivotal supplier test details for constraints located in the Met-Ed Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brunner Island - Yorkana	Peak	69	470	11	1	9
	Off Peak	69	416	6	0	6
Jackson - TMI	Peak	54	313	10	2	8
	Off Peak	61	452	9	1	8

Table 2-28 Three pivotal supplier results summary for constraints located in the PECO Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-24)

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
Eddystone - Saville	Peak	855	76	9%	849	99%
	Off Peak	NA	NA	NA	NA	NA

Table 2-29 Three pivotal supplier test details for constraints located in the PECO Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-25)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Eddystone - Saville	Peak	9	34	3	0	3
	Off Peak	NA	NA	NA	NA	NA

Table 2-30 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-26)

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
Altoona - Bear Rock	Peak	910	0	0%	910	100%
	Off Peak	327	0	0%	327	100%
Bear Rock - Johnstown	Peak	1,953	0	0%	1,953	100%
	Off Peak	52	0	0%	52	100%
East Sayre - East Towanda	Peak	274	0	0%	274	100%
	Off Peak	369	0	0%	369	100%
Roxbury - Shade Gap	Peak	1,102	0	0%	1,102	100%
	Off Peak	619	0	0%	619	100%

Table 2-31 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-27)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Altoona - Bear Rock	Peak	17	31	2	0	2
	Off Peak	22	15	1	0	1
Bear Rock - Johnstown	Peak	24	43	2	0	2
	Off Peak	12	31	2	0	2
East Sayre - East Towanda	Peak	15	18	2	0	2
	Off Peak	7	16	2	0	2
Roxbury - Shade Gap	Peak	14	14	3	0	3
	Off Peak	22	21	3	0	3

Table 2-32 Three pivotal supplier results summary for constraints located in the Pepco Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-28)

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
Burtonsville - Sandy Springs	Peak	907	11	1%	901	99%
	Off Peak	NA	NA	NA	NA	NA

Table 2-33 Three pivotal supplier test details for constraints located in the Pepco Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-29)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burtonsville - Sandy Springs	Peak	60	275	7	0	6
	Off Peak	NA	NA	NA	NA	NA

Table 2-34 Three pivotal supplier results summary for constraints located in the PPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

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
Eldred - Sunbury	Peak	1,526	0	0%	1,526	100%
	Off Peak	30	0	0%	30	100%
Harwood - Siegfried	Peak	2,892	53	2%	2,873	99%
	Off Peak	2,054	6	0%	2,053	100%

Table 2-35 Three pivotal supplier test details for constraints located in the PPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Eldred - Sunbury	Peak	30	92	4	0	4
	Off Peak	18	69	3	0	3
Harwood - Siegfried	Peak	86	532	6	0	6
	Off Peak	96	570	6	0	6

Table 2-36 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: July 1, 2010 through September 30, 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
Bergen - Hoboken	Peak	337	0	0%	337	100%
	Off Peak	300	0	0%	300	100%
Branchburg - Readington	Peak	508	4	1%	507	100%
	Off Peak	17	0	0%	17	100%
Linden - North Ave	Peak	802	0	0%	802	100%
	Off Peak	4	0	0%	4	100%

Table 2-37 Three pivotal supplier test details for constraints located in the PSEG Control Zone: July 1, 2010 through September 30, 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
Bergen - Hoboken	Peak	59	76	1	0	1
	Off Peak	17	30	1	0	1
Branchburg - Readington	Peak	38	85	4	0	4
	Off Peak	13	37	2	0	2
Linden - North Ave	Peak	94	114	1	0	1
	Off Peak	52	85	1	0	1

Market Performance: Markup

Real-Time Markup

Ownership of Marginal Resources

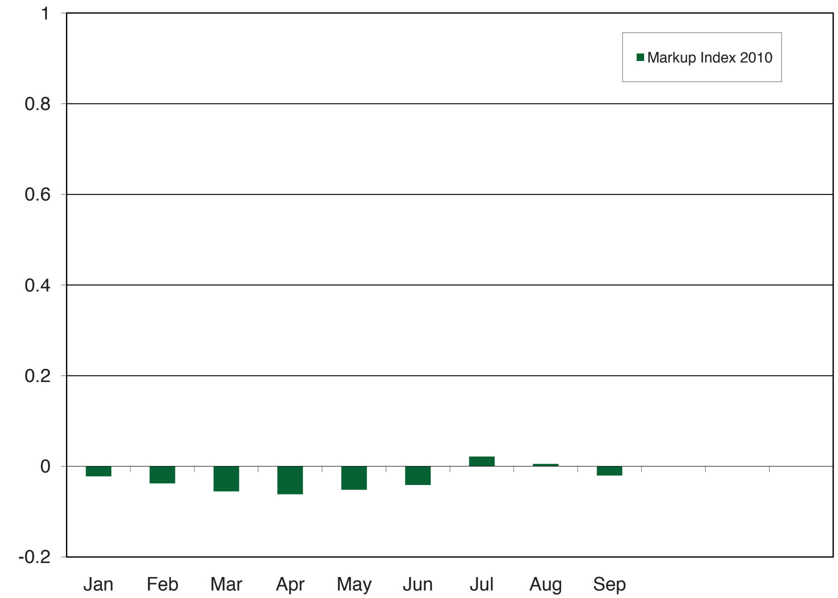
Table 2-38 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through September 2010 (See 2009 SOM, Table 2-32)

Company	Percent of Price
1	16%
2	12%
3	10%
4	6%
5	5%
6	5%
7	4%
8	4%
9	4%
Other (54 companies)	34%

Table 2-39 Type of fuel used (By real-time marginal units): January through September 2010 (See 2009 SOM, Table 2-33)

Fuel Type	2010
Coal	66%
Natural Gas	26%
Petroleum	4%
Wind	2%
Landfill Gas	1%
Misc	1%

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



Unit Markup Characteristics

Table 2-40 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September 2010 (See 2009 SOM, Table 2-34)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.14)	(234.6%)
Gas	CC	$0.97	199.5%
Gas	CT	$0.41	85.0%
Gas	Diesel	($0.00)	(0.1%)
Gas	Steam	$0.04	8.4%
Interface	Interface	($0.00)	(0.0%)
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.01	2.1%
Oil	CT	$0.02	5.1%
Oil	Diesel	($0.00)	(0.8%)
Oil	Steam	$0.14	28.7%
Uranium	Steam	$0.00	0.0%
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.03	6.7%
Total		$0.49	100.0%

Table 2-41 Average, real-time marginal unit markup index (By price category): January through September 2010 (See 2009 SOM, Table 2-35)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.10)	($3.27)
$25 to $50	(0.07)	($2.89)
$50 to $75	0.04	$1.88
$75 to $100	0.09	$7.39
$100 to $125	0.10	$10.75
$125 to $150	0.12	$16.48
> $150	0.08	$17.32

Markup Component of System Price

Table 2-42 Monthly markup components of real-time load-weighted LMP: January through September 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	($1.46)	($2.09)	($0.71)
Jul	$7.22	$12.54	$1.65
Aug	$3.53	$6.77	($0.28)
Sep	$0.66	$2.15	($1.08)
2010	$0.49	$2.04	($1.18)

Markup by Real-Time System Price Levels

Table 2-43 Average real-time markup component (By price category): January through September 2010 (See 2009 SOM, Table 2-38)

	Average Markup Component	Frequency
Below $20	($1.82)	2.4%
$20 to $40	($3.35)	53.4%
$40 to $60	($0.87)	26.6%
$60 to $80	$6.12	8.8%
$80 to $100	$1.97	3.9%
$100 to $120	$16.83	2.1%
$120 to $140	$19.36	1.2%
$140 to $160	$22.63	0.6%
Above $160	$52.94	0.9%

Day-Ahead Markup

Ownership of Marginal Resources

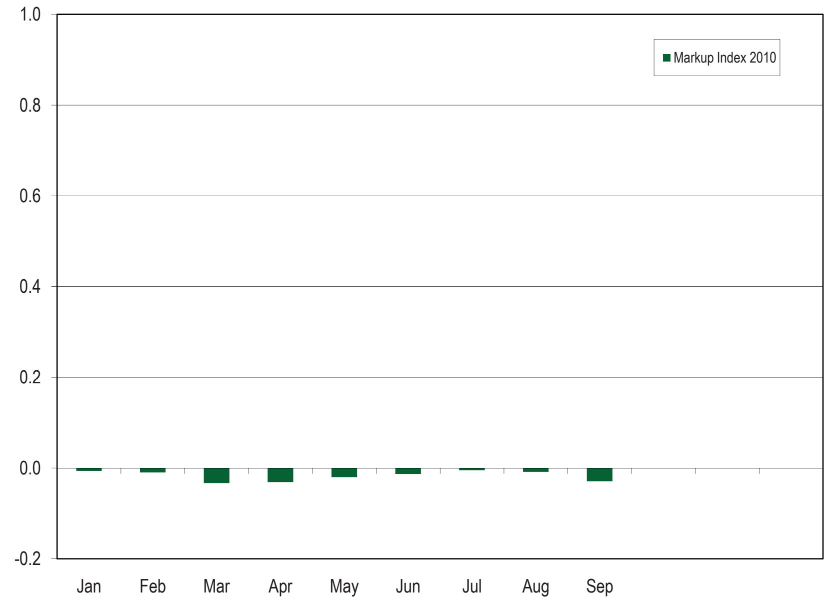
Table 2-44 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through September 2010 (See 2009 SOM, Table 2-39)

Company	Percent of Price
1	24%
2	6%
3	5%
4	5%
5	5%
6	5%
7	5%
8	4%
9	3%
Other (131 companies)	38%

Table 2-45 Day-ahead marginal resources by type/fuel: January through September 2010 (See 2009 SOM, Table 2-40)

Type/Fuel	2010
Transaction	38%
DEC	27%
INC	22%
Coal	9%
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 September 2010 (See 2009 SOM, Figure 2-6)



Unit Markup Characteristics

Table 2-46 Average, day-ahead marginal unit markup index (By primary fuel and unit type): January through September 2010 (See 2009 SOM, Table 2-41)

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	(0.07)	($2.51)
Diesel	Diesel	(0.24)	($16.12)
Municipal waste	Steam	0.00	$0.06
Natural gas	CT	0.07	$4.64
Natural gas	Diesel	(0.03)	($2.24)
Natural gas	Steam	0.01	$0.91
Oil	Steam	0.02	$4.67
Wind	Wind	0.00	$0.00

Table 2-47 Average, day-ahead marginal unit markup index (By price category): January through September 2010 (See 2009 SOM, Table 2-42)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.11)	($3.40)
$25 to $50	(0.05)	($2.18)
$50 to $75	0.03	$1.56
$75 to $100	0.14	$11.18
$100 to $125	0.01	$1.08
$125 to $150	0.26	$34.46
> $150	0.28	$54.75

Markup Component of System Price

Table 2-48 Monthly markup components of day-ahead, load-weighted LMP: January through September 2010 (See 2009 SOM, Table 2-43)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.42)	($0.12)	($0.67)
Feb	($0.52)	($0.27)	($0.79)
Mar	($1.46)	($0.92)	($2.10)
Apr	($1.23)	($0.74)	($1.83)
May	($0.72)	($0.09)	($1.31)
Jun	($0.47)	$0.14	($1.20)
Jul	$0.29	$1.49	($0.96)
Aug	($0.16)	$0.87	($1.37)
Sep	($1.17)	($0.54)	($1.89)
Annual	($0.60)	$0.04	($1.29)

Markup by System Price Levels

Table 2-49 Average, day-ahead markup (By price category): January through September 2010 (See 2009 SOM, Table 2-45)

	Average Markup Component	Frequency
Below $20	($2.85)	0%
$20 to $40	($2.22)	52%
$40 to $60	($0.22)	35%
$60 to $80	$0.66	8%
$80 to $100	$2.43	3%
$100 to $120	$2.34	1%
$120 to $140	$2.29	0%
$140 to $160	$21.36	0%
Above $160	($15.75)	0%

Markup Component by Fuel, Unit Type

Table 2-50 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September 2010 (See 2009 SOM, Table 2-46)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.72)	120.6%
Diesel	Diesel	($0.00)	0.8%
Municipal waste	Steam	$0.00	(0.0%)
Natural gas	CT	$0.03	(4.4%)
Natural gas	Diesel	($0.00)	0.3%
Natural gas	Steam	$0.09	(15.0%)
Oil	Steam	$0.01	(2.3%)
Wind	Wind	$0.00	0.0%
Total		($0.60)	100.0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-51 Frequently mitigated units and associated units (By month): January through September 2010 (See 2009 SOM, Table 2-47)

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
Jan	35	31	27	93
Feb	35	28	31	94
Mar	42	16	44	102
Apr	38	13	47	98
May	35	19	35	89
Jun	29	16	41	86
Jul	21	21	46	88
Aug	25	31	59	115
Sep	34	31	56	121

Table 2-52 Frequently mitigated units and associated units total months eligible: January through September 2010 (See 2009 SOM, Table 2-48)

Months Adder-Eligible	FMU & AU Count
Jan	25
Feb	18
Mar	8
Apr	6
May	11
Jun	9
Jul	12
Aug	10
Sep	56
Total	155

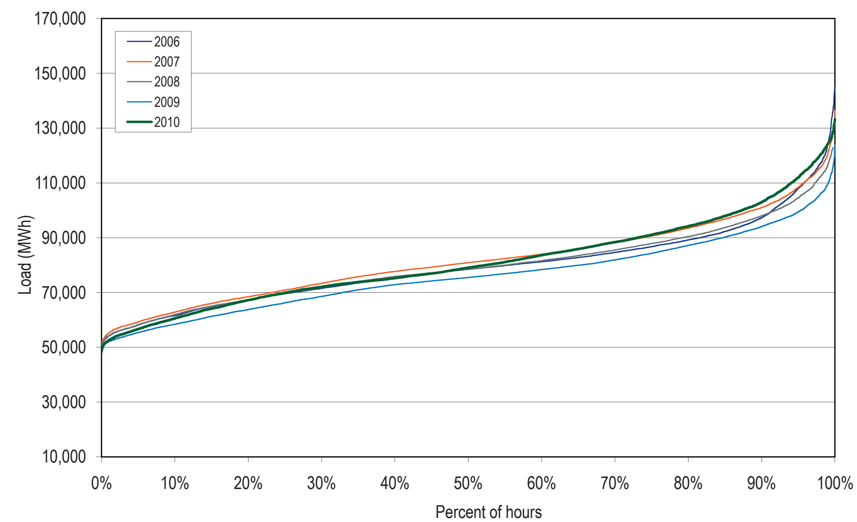
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

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



PJM Real-Time, Annual Average Load

Table 2-53 PJM real-time average load: Calendar years 1998 through September 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	81,068	79,053	16,209	6.6%	4.7%	22.2%

PJM Real-Time, Monthly Average Load

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

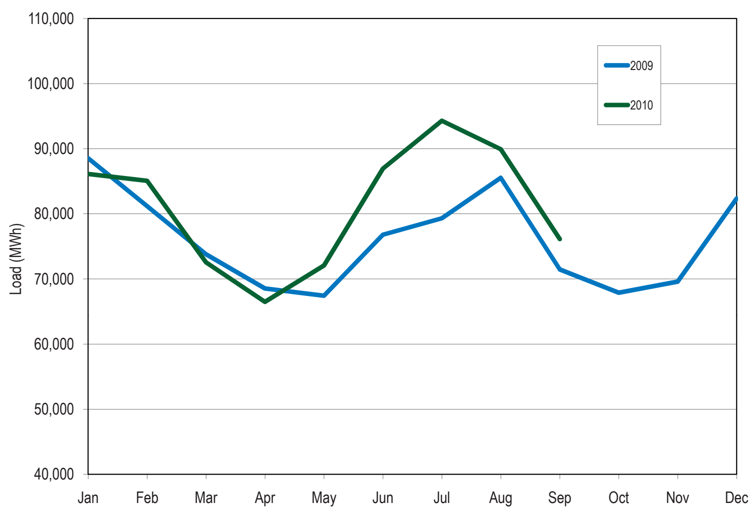


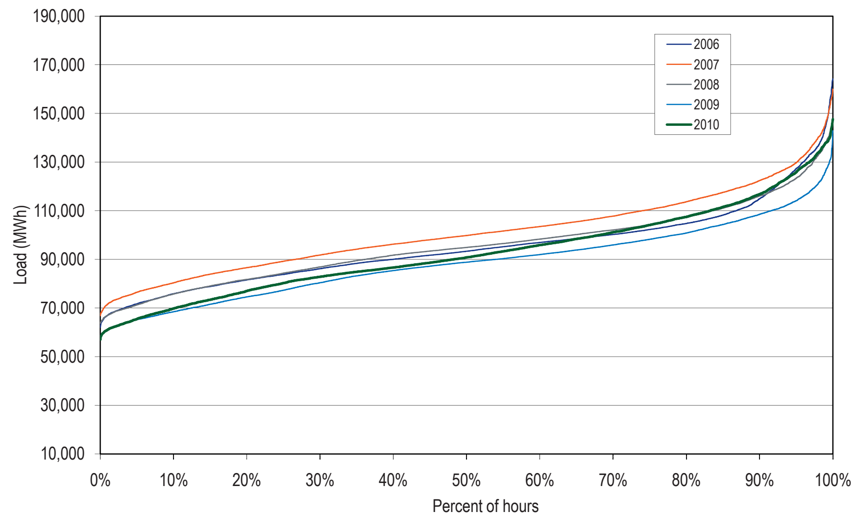
Table 2-54 PJM annual Summer THI, Winter WWP and average temperature: cooling, heating and shoulder months of 2006 through September 2010 (See 2009 SOM, Table 2-51)

	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	77.36	24.47	60.07

Day-Ahead Load

PJM Day-Ahead Load Duration

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



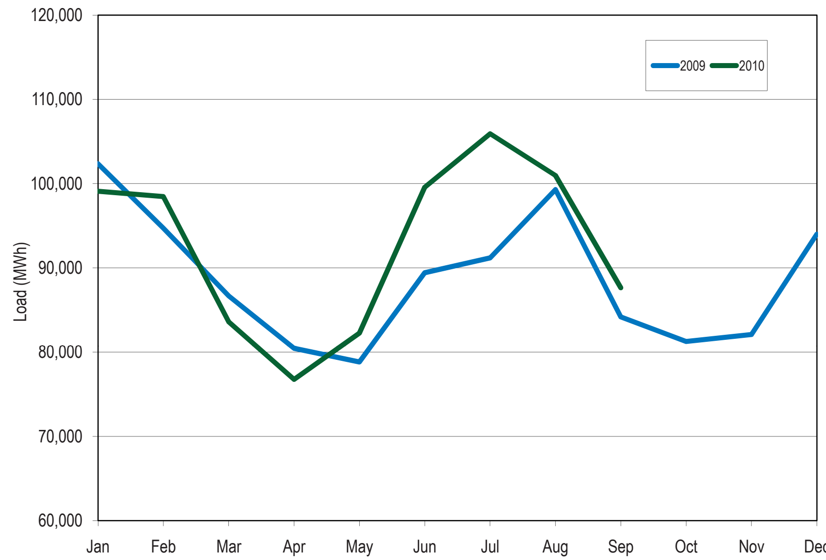
PJM Day-Ahead, Annual Average Load

Table 2-55 PJM day-ahead average load: Calendar years 2000 through September 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	92,683	90,804	17,769	4.5%	2.2%	19.3%

PJM Day-Ahead, Monthly Average Load

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



Real-Time and Day-Ahead Load

Table 2-56 Cleared day-ahead and real-time load (MWh): January through September 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	75,788	1,264	16,254	93,306	81,679	11,628	(4,627)
Median	73,674	1,156	16,185	91,223	79,548	11,674	(4,510)
Standard deviation	15,211	489	2,648	17,765	16,242	1,523	(1,125)
Peak average	84,175	1,459	17,641	103,275	90,300	12,975	(4,666)
Peak median	82,487	1,350	17,574	101,372	88,431	12,941	(4,634)
Peak standard deviation	13,548	485	2,169	15,381	14,612	769	(1,400)
Off peak average	68,454	1,094	15,042	84,590	74,141	10,449	(4,593)
Off peak median	67,006	1,007	14,837	82,793	72,651	10,142	(4,695)
Off peak standard deviation	12,567	425	2,425	14,896	13,639	1,257	(1,168)

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

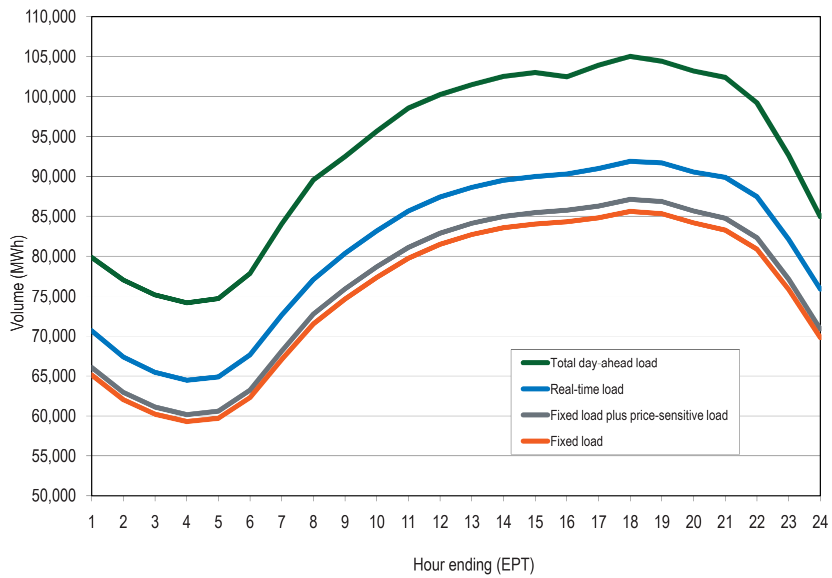
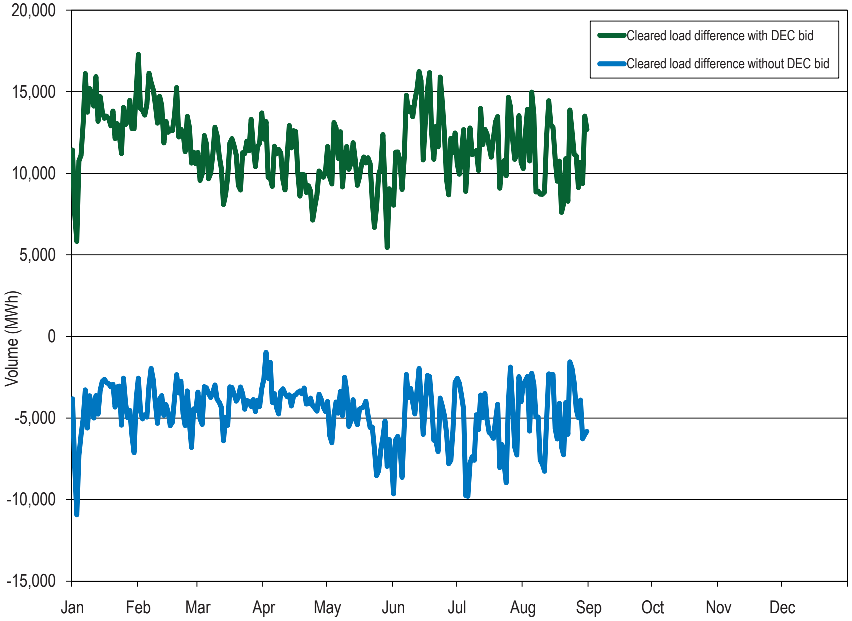


Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): January through September 2010 (New Figure)



Day-Ahead and Real-Time Generation

Table 2-57 Day-ahead and real-time generation (MWh): January through September 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	85,366	11,161	96,527	84,542	825	11,986
Median	83,486	11,023	94,448	82,508	978	11,940
Standard deviation	17,552	1,610	18,199	16,448	1,104	1,751
Peak average	94,654	12,011	106,665	93,019	1,636	13,647
Peak median	92,836	11,945	104,597	91,054	1,782	13,543
Peak standard deviation	15,294	1,486	15,766	14,772	522	993
Off peak average	77,246	10,417	87,663	77,130	116	10,533
Off peak median	75,849	10,420	85,949	75,881	(32)	10,067
Off peak standard deviation	15,217	1,321	15,332	14,091	1,127	1,241

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

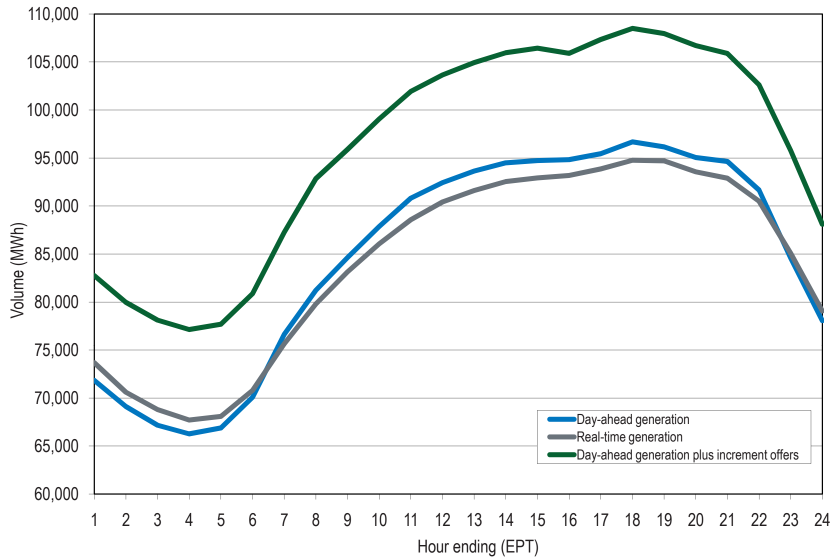
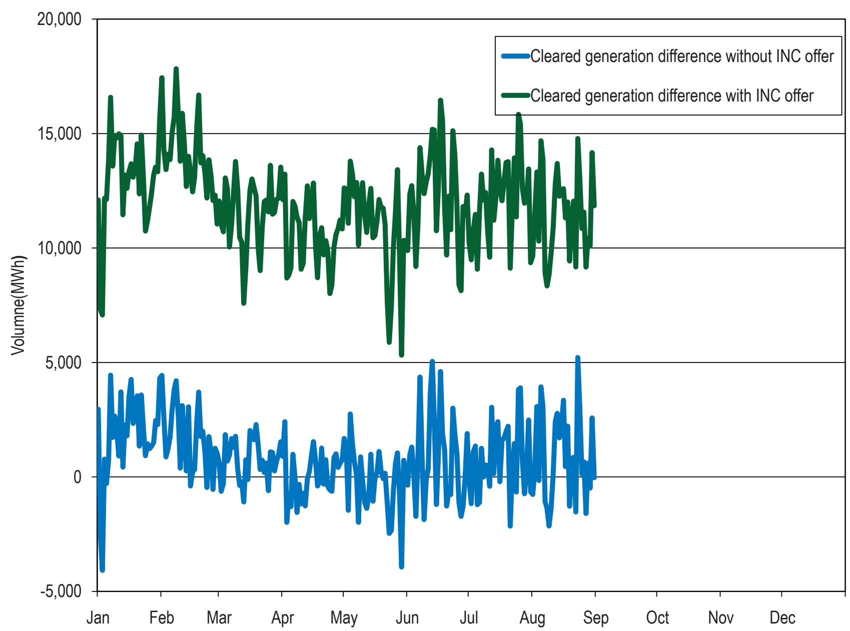


Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January through September 2010 (New Figure)



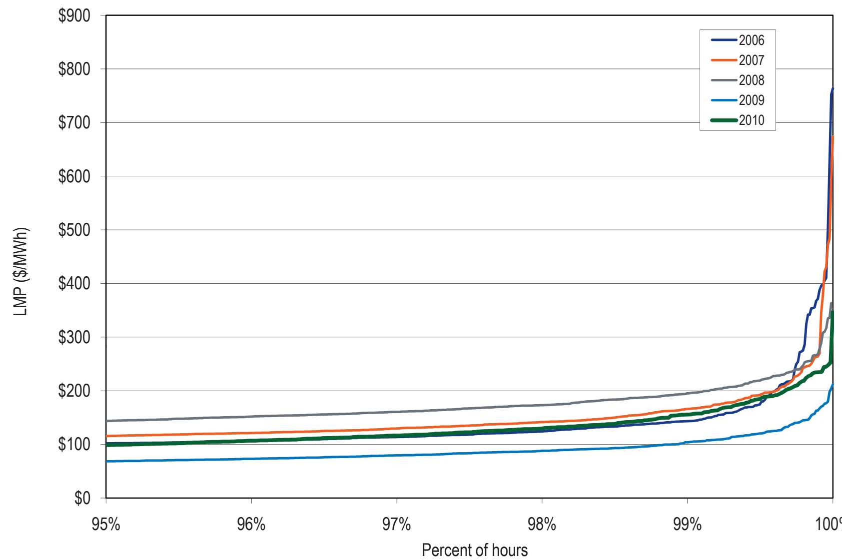
Locational Marginal Price (LMP)

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 September 2010 (See 2009 SOM, Figure 2-13)



PJM Real-Time, Annual Average LMP

Table 2-58 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 through September 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	$46.13	$37.89	$26.99	24.4%	15.8%	57.6%

Table 2-59 PJM real-time, simple average LMP (Dollars per MWh): January through September 2006, 2007, 2008, 2009 and 2010 (New Table)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2006 (Jan - Sep)	$51.79	$43.50	$34.93	NA	NA	NA
2007 (Jan - Sep)	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008 (Jan - Sep)	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009 (Jan - Sep)	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010 (Jan - Sep)	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%

Zonal Real-Time, Annual Average LMP

Table 2-60 Zonal real-time, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-56)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AECO	$41.33	$52.40	$11.07	26.8%
AEP	$33.81	$39.13	$5.32	15.7%
AP	$38.89	$45.30	$6.41	16.5%
BGE	$42.04	$55.05	$13.01	30.9%
ComEd	$28.78	$35.31	$6.53	22.7%
DAY	$33.56	$39.16	$5.60	16.7%
DLCO	$32.47	$38.17	$5.71	17.6%
Dominion	$40.55	$52.11	$11.56	28.5%
DPL	$42.02	$52.64	$10.62	25.3%
JCPL	$41.39	$51.17	$9.78	23.6%
Met-Ed	$40.40	$50.90	$10.50	26.0%
PECO	$40.51	$50.71	$10.20	25.2%
PENELEC	$37.13	$43.38	$6.25	16.8%
Pepco	$42.26	$54.04	$11.78	27.9%
PPL	$39.87	$49.23	$9.36	23.5%
PSEG	$41.88	$52.03	$10.14	24.2%
RECO	$40.85	$50.14	$9.29	22.7%
PJM	$37.42	$46.13	$8.70	23.3%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-61 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-57)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
Delaware	$41.56	$51.69	$10.13	24.4%
Illinois	$28.78	$35.31	$6.53	22.7%
Indiana	$33.26	$38.36	$5.10	15.3%
Kentucky	$33.63	$39.32	$5.69	16.9%
Maryland	$42.03	$54.51	$12.48	29.7%
Michigan	$34.48	$39.05	$4.57	13.3%
New Jersey	$41.65	$51.82	$10.17	24.4%
North Carolina	$39.56	$50.13	$10.56	26.7%
Ohio	$33.33	$38.47	$5.14	15.4%
Pennsylvania	$38.86	$47.32	$8.46	21.8%
Tennessee	$33.69	$40.06	$6.37	18.9%
Virginia	$39.83	$50.55	$10.73	26.9%
West Virginia	$35.03	$39.82	$4.80	13.7%
District of Columbia	$43.74	$54.21	$10.47	23.9%

Hub Real-Time, Annual Average LMP

Table 2-62 Hub real-time, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-58)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AEP Gen Hub	$31.90	$36.53	$4.64	14.5%
AEP-DAY Hub	$33.39	$38.48	$5.09	15.2%
Chicago Gen Hub	$27.98	$34.17	$6.19	22.1%
Chicago Hub	$28.98	$35.53	$6.55	22.6%
Dominion Hub	$39.88	$50.56	$10.68	26.8%
Eastern Hub	$41.97	$52.60	$10.63	25.3%
N Illinois Hub	$28.60	$35.06	$6.46	22.6%
New Jersey Hub	$41.61	$51.70	$10.09	24.2%
Ohio Hub	$33.39	$38.57	$5.18	15.5%
West Interface Hub	$34.73	$41.57	$6.84	19.7%
Western Hub	$38.64	$46.70	$8.06	20.9%

Real-Time, Load-Weighted, Average LMP

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

Table 2-63 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through September 2010 (See 2009 SOM, Table 2-59)

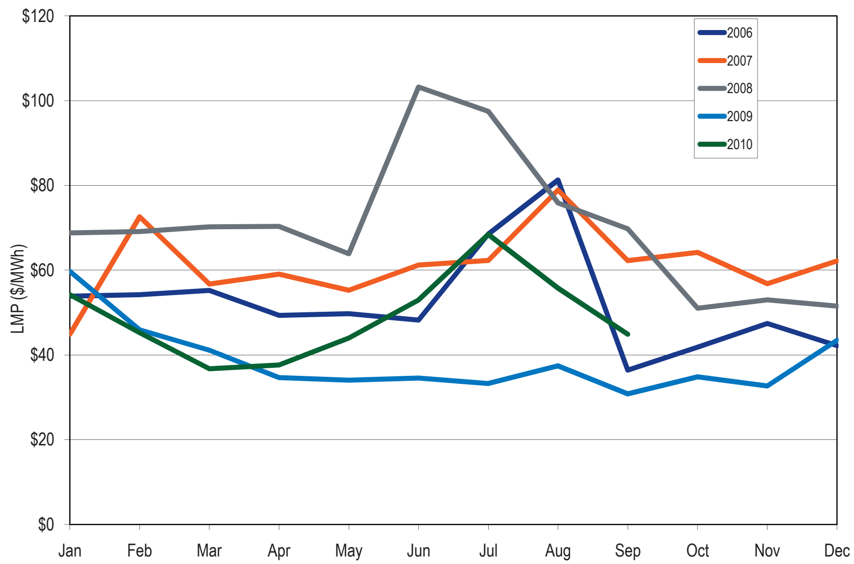
	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
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	$49.91	$40.33	$29.65	27.8%	17.8%	62.8%

Table 2-64 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2006, 2007, 2008, 2009 and 2010 (New Table)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2006 (Jan - Sep)	$56.39	$46.82	$40.70	NA	NA	NA
2007 (Jan - Sep)	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008 (Jan - Sep)	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009 (Jan - Sep)	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010 (Jan - Sep)	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%

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

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



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

Table 2-65 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-60)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AECO	$43.27	$59.51	$16.24	37.5%
AEP	$35.56	$41.37	$5.81	16.3%
AP	$41.49	$48.37	$6.88	16.6%
BGE	$44.83	$60.99	$16.16	36.0%
ComEd	$30.60	$38.46	$7.87	25.7%
DAY	$35.30	$41.82	$6.52	18.5%
DLCO	$33.65	$40.69	$7.04	20.9%
Dominion	$43.46	$57.51	$14.05	32.3%
DPL	$45.13	$58.42	$13.29	29.4%
JCPL	$43.78	$57.98	$14.20	32.4%
Met-Ed	$43.01	$55.45	$12.44	28.9%
PECO	$42.69	$55.59	$12.89	30.2%
PENELEC	$39.03	$45.58	$6.55	16.8%
Pepco	$45.10	$59.69	$14.59	32.3%
PPL	$42.83	$53.23	$10.40	24.3%
PSEG	$43.74	$57.37	$13.62	31.1%
RECO	$42.91	$56.61	$13.69	31.9%
PJM	$39.57	$49.91	$10.35	26.2%

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

Table 2-66 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-61)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
Delaware	$44.21	$57.03	$12.82	29.0%
Illinois	$30.60	$38.46	$7.87	25.7%
Indiana	$34.42	$40.11	$5.69	16.5%
Kentucky	$36.18	$41.92	$5.75	15.9%
Maryland	$45.12	$60.53	$15.41	34.2%
Michigan	$35.78	$41.72	$5.94	16.6%
New Jersey	$43.67	$57.83	$14.15	32.4%
North Carolina	$42.10	$55.17	$13.07	31.0%
Ohio	$34.92	$40.71	$5.79	16.6%
Pennsylvania	$41.12	$50.96	$9.84	23.9%
Tennessee	$35.88	$42.86	$6.97	19.4%
Virginia	$42.77	$55.53	$12.76	29.8%
West Virginia	$37.24	$42.08	$4.84	13.0%
District of Columbia	$46.29	$58.79	$12.51	27.0%

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

Fuel Cost

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

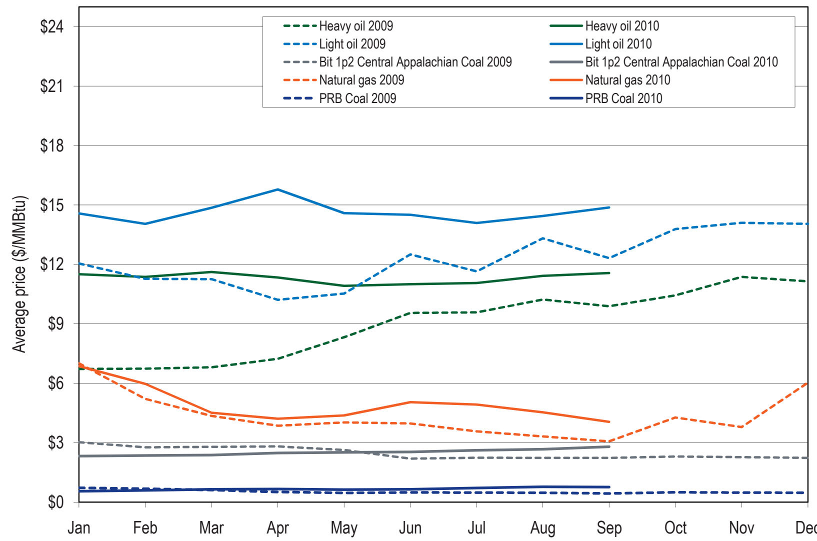


Figure 2-18 Spot average emission price comparison: Calendar years 2009 through September 2010 (See 2009 SOM, Figure 2-16)

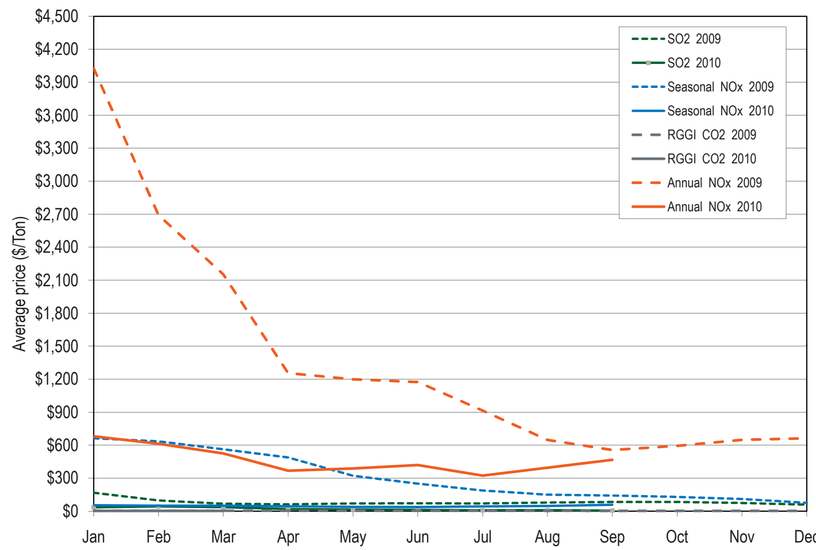


Table 2-67 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2009 SOM, Table 2-62)

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
September 10, 2010	$1.86	45,595,968	34,407,000

Table 2-68 PJM real-time annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-63)

	2010 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$49.91	$49.74	(0.3%)
	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$39.57	$49.74	25.7%
	2009 Load-Weighted LMP	2010 Load-Weighted LMP	Change
Average	$39.57	$49.91	26.2%

Components of Real-Time, Load-Weighted LMP

Table 2-69 Components of PJM real-time, annual, load-weighted, average LMP: January 1, 2010, through September 30, 2010 (See 2009 SOM, Table 2-64)

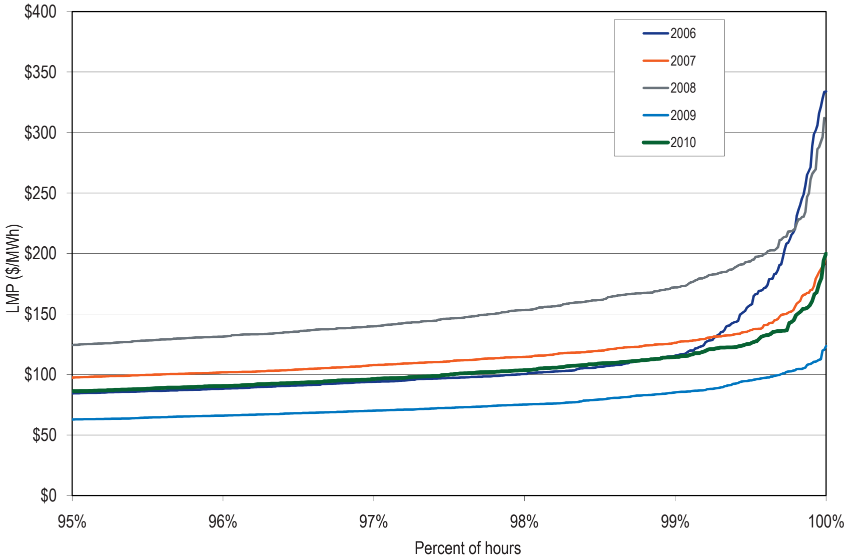
Element	Contribution to LMP	Percent
Gas	$20.03	40.1%
Coal	$18.81	37.7%
10% Cost Adder	$4.43	8.9%
VOM	$2.89	5.8%
Oil	$2.00	4.0%
NOx	$1.08	2.2%
CO2	$0.60	1.2%
Markup	$0.49	1.0%
NA	$0.35	0.7%
SO2	$0.18	0.4%
FMU Adder	$0.16	0.3%
M2M Adder	$0.01	0.0%
Shadow Price Limit Adder	$0.01	0.0%
Offline CT Adder	$0.00	0.0%
Unit LMP Differential	$0.00	0.0%
Municipal Waste	($0.00)	(0.0%)
UDS Override Differential	($0.54)	(1.1%)
Dispatch Differential	($0.58)	(1.2%)
LMP	$49.91	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 September 2010 (See 2009 SOM, Figure 2-17)



PJM Day-Ahead, Annual Average LMP

Table 2-70 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 through September 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	$45.81	$41.03	$19.59	23.8%	16.7%	46.4%

Table 2-71 PJM day-ahead, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (New Table)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2006 (Jan - Sep)	$50.45	$46.32	$24.93	NA	NA	NA
2007 (Jan - Sep)	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008 (Jan - Sep)	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009 (Jan - Sep)	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010 (Jan - Sep)	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%

Zonal Day-Ahead, Annual Average LMP

Table 2-72 Zonal day-ahead, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-66)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AECO	$42.15	$51.79	$9.64	22.9%
AEP	$33.70	$39.00	$5.30	15.7%
AP	$38.37	$45.16	$6.79	17.7%
BGE	$42.75	$54.65	$11.90	27.8%
ComEd	$28.80	$35.29	$6.49	22.5%
DAY	$33.07	$38.85	$5.78	17.5%
DLCO	$32.25	$38.90	$6.65	20.6%
Dominion	$41.07	$52.22	$11.15	27.1%
DPL	$42.43	$52.02	$9.59	22.6%
JCPL	$41.99	$51.29	$9.30	22.1%
Met-Ed	$40.87	$50.59	$9.72	23.8%
PECO	$41.37	$50.90	$9.52	23.0%
PENELEC	$37.46	$44.39	$6.93	18.5%
Pepco	$42.91	$54.25	$11.34	26.4%
PPL	$40.45	$49.05	$8.60	21.3%
PSEG	$42.56	$52.04	$9.48	22.3%
RECO	$41.51	$50.86	$9.35	22.5%
PJM	$37.35	$45.81	$8.46	22.7%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-73 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-67)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
Delaware	$41.81	$50.94	$9.13	21.8%
Illinois	$28.80	$35.29	$6.49	22.5%
Indiana	$33.14	$38.26	$5.12	15.4%
Kentucky	$33.41	$39.08	$5.67	17.0%
Maryland	$42.64	$54.46	$11.82	27.7%
Michigan	$34.41	$38.87	$4.46	13.0%
New Jersey	$42.33	$51.79	$9.46	22.4%
North Carolina	$40.03	$50.39	$10.36	25.9%
Ohio	$33.00	$38.20	$5.19	15.7%
Pennsylvania	$39.29	$47.46	$8.18	20.8%
Tennessee	$33.90	$40.05	$6.14	18.1%
Virginia	$40.37	$50.86	$10.50	26.0%
West Virginia	$34.80	$39.69	$4.89	14.1%
District of Columbia	$44.06	$54.28	$10.22	23.2%

Day-Ahead, Load-Weighted, Average LMP

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

Table 2-74 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through September 2010 (See 2009 SOM, Table 2-68)

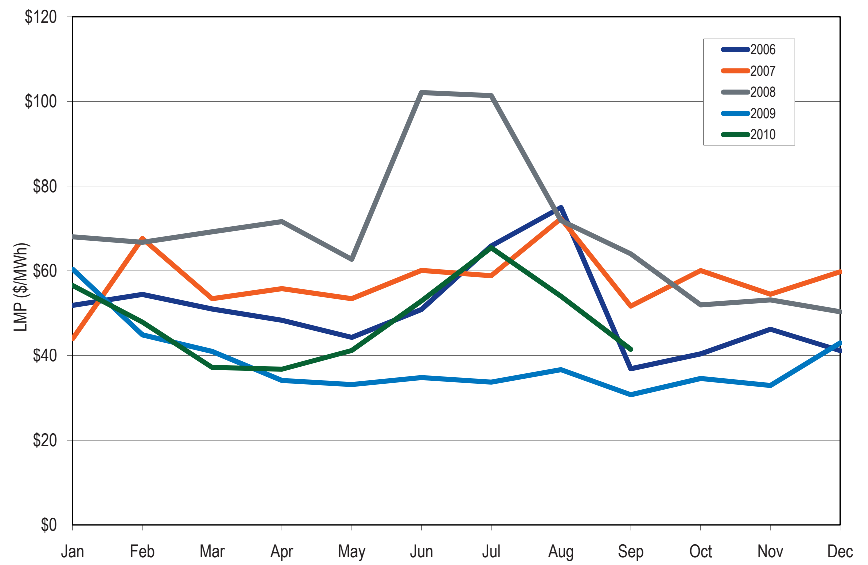
	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
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	$49.12	$43.33	$21.35	26.5%	18.2%	52.2%

Table 2-75 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September 2006, 2007, 2008, 2009 to 2010 (New Table)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2006 (Jan - Sep)	$54.19	$48.87	$28.35	NA	NA	NA
2007 (Jan - Sep)	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008 (Jan - Sep)	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009 (Jan - Sep)	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010 (Jan - Sep)	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%

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

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



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-76 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through September 2009 to 2010 (See 2009 SOM, Table 2-69)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AECO	$44.48	$59.13	$14.65	32.9%
AEP	$35.37	$41.23	$5.87	16.6%
AP	$40.77	$47.83	$7.06	17.3%
BGE	$45.38	$60.25	$14.87	32.8%
ComEd	$30.11	$37.68	$7.58	25.2%
DAY	$34.63	$41.31	$6.69	19.3%
DLCO	$33.33	$41.37	$8.05	24.2%
Dominion	$43.87	$57.37	$13.49	30.8%
DPL	$45.11	$57.37	$12.26	27.2%
JCPL	$44.22	$56.70	$12.48	28.2%
Met-Ed	$43.54	$54.68	$11.14	25.6%
PECO	$43.49	$55.30	$11.81	27.2%
PENELEC	$39.06	$46.03	$6.97	17.8%
Pepco	$45.43	$57.89	$12.46	27.4%
PPL	$43.14	$52.44	$9.30	21.6%
PSEG	$44.48	$56.46	$11.98	26.9%
RECO	$43.93	$57.14	$13.21	30.1%
PJM	$39.35	$49.12	$9.77	24.8%

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

Table 2-77 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-70)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
Delaware	$44.31	$55.79	$11.48	25.9%
Illinois	$30.11	$37.68	$7.58	25.2%
Indiana	$34.23	$40.24	$6.01	17.6%
Kentucky	$35.77	$41.42	$5.65	15.8%
Maryland	$45.41	$59.30	$13.89	30.6%
Michigan	$35.58	$40.56	$4.97	14.0%
New Jersey	$44.38	$56.88	$12.49	28.2%
North Carolina	$42.71	$55.39	$12.68	29.7%
Ohio	$34.56	$40.36	$5.80	16.8%
Pennsylvania	$41.36	$50.45	$9.09	22.0%
Tennessee	$35.96	$42.64	$6.68	18.6%
Virginia	$43.12	$55.60	$12.48	29.0%
West Virginia	$36.74	$42.06	$5.32	14.5%
District of Columbia	$46.86	$57.59	$10.72	22.9%

Components of Day-Ahead, Load-Weighted LMP

Table 2-78 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-71)

Element	Contribution to LMP	Percent
INC	$18.42	37.5%
DEC	$13.14	26.7%
Coal	$6.98	14.2%
Natural gas	$5.83	11.9%
Transaction	$1.52	3.1%
10% Cost offer	$1.45	2.9%
VOM	$0.83	1.7%
Price sensitive demand	$0.70	1.4%
NOx	$0.35	0.7%
CO2	$0.22	0.4%
Oil	$0.17	0.4%
Constrained off	$0.12	0.2%
SO2	$0.06	0.1%
Diesel	$0.01	0.0%
FMU adder	$0.00	0.0%
Markup	($0.60)	(1.2%)
NA	($0.09)	(0.2%)
Total	$49.12	100.0%

Marginal Losses

Table 2-79 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through September 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	$46.13	$46.03	$0.06	$0.04

Table 2-80 Zonal real-time, simple average LMP components (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-73)

	2009 (Jan - Sep)				2010 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$41.33	$37.35	$2.13	$1.85	$52.40	$46.03	$3.87	$2.50
AEP	$33.81	$37.35	($2.32)	($1.23)	$39.13	$46.03	($5.23)	($1.66)
AP	$38.89	$37.35	$1.62	($0.08)	$45.30	$46.03	($0.42)	($0.31)
BGE	$42.04	$37.35	$3.05	$1.65	$55.05	$46.03	$6.72	$2.30
ComEd	$28.78	$37.35	($6.24)	($2.33)	$35.31	$46.03	($7.87)	($2.84)
DAY	$33.56	$37.35	($2.99)	($0.80)	$39.16	$46.03	($5.92)	($0.95)
DLCO	$32.47	$37.35	($3.53)	($1.35)	$38.17	$46.03	($6.08)	($1.78)
Dominion	$40.55	$37.35	$2.60	$0.60	$52.11	$46.03	$5.31	$0.78
DPL	$42.02	$37.35	$2.67	$2.00	$52.64	$46.03	$3.99	$2.63
JCPL	$41.39	$37.35	$2.11	$1.93	$51.17	$46.03	$2.79	$2.35
Met-Ed	$40.40	$37.35	$2.21	$0.83	$50.90	$46.03	$3.78	$1.09
PECO	$40.51	$37.35	$1.88	$1.28	$50.71	$46.03	$2.99	$1.69
PENELEC	$37.13	$37.35	($0.04)	($0.17)	$43.38	$46.03	($2.36)	($0.29)
Pepco	$42.26	$37.35	$3.82	$1.09	$54.04	$46.03	$6.61	$1.40
PPL	$39.87	$37.35	$1.90	$0.63	$49.23	$46.03	$2.38	$0.82
PSEG	$41.88	$37.35	$2.53	$2.01	$52.03	$46.03	$3.59	$2.41
RECO	$40.85	$37.35	$1.73	$1.77	$50.14	$46.03	$2.04	$2.08

Table 2-81 Hub real-time, simple average LMP components (Dollars per MWh): January through September 2010 (See 2009 SOM, 2-74)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$36.53	$46.03	($6.29)	($3.21)
AEP-DAY Hub	$38.48	$46.03	($5.70)	($1.85)
Chicago Gen Hub	$34.17	$46.03	($8.40)	($3.46)
Chicago Hub	$35.53	$46.03	($7.67)	($2.82)
Dominion Hub	$50.56	$46.03	$4.29	$0.25
Eastern Hub	$52.60	$46.03	$3.76	$2.82
N Illinois Hub	$35.06	$46.03	($7.89)	($3.08)
New Jersey Hub	$51.70	$46.03	$3.32	$2.35
Ohio Hub	$38.57	$46.03	($5.69)	($1.76)
West Interface Hub	$41.57	$46.03	($2.85)	($1.60)
Western Hub	$46.70	$46.03	$1.01	($0.34)

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

Table 2-82 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-75)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$59.51	$51.05	$5.58	$2.88
AEP	$41.37	$49.05	($5.91)	($1.78)
AP	$48.37	$49.35	($0.62)	($0.36)
BGE	$60.99	$50.23	$8.21	$2.54
ComEd	$38.46	$49.58	($8.19)	($2.93)
DAY	$41.82	$49.64	($6.86)	($0.96)
DLCO	$40.69	$49.52	($6.89)	($1.94)
Dominion	$57.51	$50.39	$6.29	$0.83
DPL	$58.42	$50.68	$4.78	$2.96
JCPL	$57.98	$51.43	$3.91	$2.64
Met-Ed	$55.45	$49.69	$4.57	$1.18
PECO	$55.59	$49.98	$3.75	$1.85
PENELEC	$45.58	$48.62	($2.72)	($0.33)
Pepco	$59.69	$50.30	$7.89	$1.51
PPL	$53.23	$49.43	$2.91	$0.89
PSEG	$57.37	$50.32	$4.43	$2.62
RECO	$56.61	$51.42	$2.88	$2.31
PJM	$49.91	$49.81	$0.06	$0.04

Table 2-83 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 through September 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	$45.81	$45.76	$0.08	($0.03)

Table 2-84 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-77)

	2009 (Jan - Sep)				2010 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$42.15	$37.52	$2.35	$2.29	$51.79	$45.76	$2.96	$3.07
AEP	$33.70	$37.52	($2.24)	($1.58)	$39.00	$45.76	($4.41)	($2.35)
AP	$38.37	$37.52	$0.83	$0.03	$45.16	$45.76	($0.28)	($0.31)
BGE	$42.75	$37.52	$3.24	$2.00	$54.65	$45.76	$5.90	$2.99
ComEd	$28.80	$37.52	($5.61)	($3.11)	$35.29	$45.76	($6.63)	($3.85)
DAY	$33.07	$37.52	($3.01)	($1.44)	$38.85	$45.76	($5.01)	($1.90)
DLCO	$32.25	$37.52	($3.73)	($1.54)	$38.90	$45.76	($4.69)	($2.16)
Dominion	$41.07	$37.52	$2.59	$0.97	$52.22	$45.76	$5.13	$1.33
DPL	$42.43	$37.52	$2.58	$2.33	$52.02	$45.76	$3.20	$3.06
JCPL	$41.99	$37.52	$2.07	$2.41	$51.29	$45.76	$2.43	$3.10
Met-Ed	$40.87	$37.52	$2.33	$1.03	$50.59	$45.76	$3.41	$1.42
PECO	$41.37	$37.52	$2.10	$1.76	$50.90	$45.76	$2.73	$2.41
PENELEC	$37.46	$37.52	$0.01	($0.06)	$44.39	$45.76	($1.32)	($0.05)
Pepco	$42.91	$37.52	$3.78	$1.61	$54.25	$45.76	$6.29	$2.20
PPL	$40.45	$37.52	$2.12	$0.81	$49.05	$45.76	$2.26	$1.03
PSEG	$42.56	$37.52	$2.45	$2.59	$52.04	$45.76	$2.96	$3.32
RECO	$41.51	$37.52	$1.69	$2.30	$50.86	$45.76	$2.16	$2.93

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

Table 2-85 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-78)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$59.13	$51.39	$4.01	$3.73
AEP	$41.23	$48.81	($5.05)	($2.53)
AP	$47.83	$48.61	($0.43)	($0.36)
BGE	$60.25	$49.84	$7.07	$3.35
ComEd	$37.68	$48.55	($6.86)	($4.01)
DAY	$41.31	$49.09	($5.76)	($2.01)
DLCO	$41.37	$48.88	($5.16)	($2.35)
Dominion	$57.37	$49.84	$6.09	$1.44
DPL	$57.37	$50.15	$3.78	$3.44
JCPL	$56.70	$50.23	$3.04	$3.43
Met-Ed	$54.68	$49.12	$4.03	$1.53
PECO	$55.30	$49.40	$3.25	$2.65
PENELEC	$46.03	$47.59	($1.50)	($0.06)
Pepco	$57.89	$48.52	$7.02	$2.36
PPL	$52.44	$48.76	$2.56	$1.12
PSEG	$56.46	$49.47	$3.41	$3.59
RECO	$57.14	$51.16	$2.72	$3.26
PJM	$49.12	$49.05	$0.11	($0.03)

Marginal Loss Accounting

Monthly Marginal Loss Costs

Table 2-86 Marginal loss costs by type (Dollars (Millions)): January through September 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
Jul	$39.0	($180.9)	$12.0	$231.9	$1.5	($0.7)	($6.2)	($4.0)	$227.9
Aug	$16.0	($144.7)	$8.5	$169.2	$1.9	$0.5	($3.3)	($1.9)	$167.3
Sep	$11.7	($95.8)	$7.6	$115.2	$0.5	($0.6)	($3.2)	($2.0)	$113.1
Total	$219.5	($993.2)	$61.5	$1,274.2	$9.0	($6.0)	($30.0)	($15.0)	$1,259.2

Zonal Marginal Loss Costs

Table 2-87 Marginal loss costs by control zone and type (Dollars (Millions)): January through September 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	$30.6	$7.8	$0.2	$23.1	$1.4	($0.5)	($0.1)	$1.8	$24.8
AEP	($66.7)	($303.0)	$18.0	$254.2	$4.0	$3.9	($1.5)	($1.4)	$252.8
AP	($10.6)	($101.8)	$8.9	$100.1	$3.2	$5.0	($4.5)	($6.3)	$93.7
BGE	$71.8	$20.7	$3.3	$54.4	$4.3	($2.5)	($2.6)	$4.2	$58.6
ComEd	($183.8)	($405.9)	$3.9	$226.0	($7.9)	($2.7)	($2.9)	($8.1)	$217.9
DAY	($4.6)	($53.5)	$13.3	$62.1	$0.1	$1.3	($10.9)	($12.1)	$50.0
DLCO	($30.5)	($48.1)	$0.2	$17.7	($2.4)	($0.3)	($0.1)	($2.3)	$15.5
Dominion	$91.5	($48.7)	$7.1	$147.4	$3.0	($0.4)	($3.2)	$0.2	$147.5
DPL	$53.3	$11.1	$0.7	$42.9	($2.5)	($1.6)	($0.5)	($1.4)	$41.5
JCPL	$63.5	$24.3	$0.3	$39.5	$0.2	($1.1)	($0.3)	$1.0	$40.5
Met-Ed	$18.8	$3.0	$0.1	$15.9	$0.0	($0.2)	($0.1)	$0.2	$16.0
PECO	$65.9	$22.0	$0.2	$44.1	($1.1)	($0.5)	($0.1)	($0.7)	$43.4
PENELEC	($24.1)	($84.7)	($0.0)	$60.5	$3.8	($2.7)	$0.2	$6.7	$67.2
Pepco	$93.1	$41.2	$2.7	$54.6	($2.5)	($1.0)	($1.8)	($3.3)	$51.3
PJM	($84.4)	($102.3)	($8.1)	$9.7	$2.1	($9.7)	$6.1	$17.9	$27.6
PPL	$33.2	($11.6)	$1.3	$46.1	$2.1	$1.0	$0.1	$1.2	$47.2
PSEG	$99.2	$35.9	$9.5	$72.8	$0.9	$6.2	($7.8)	($13.1)	$59.7
RECO	$3.4	$0.3	$0.0	$3.1	$0.4	($0.2)	($0.0)	$0.6	$3.7
Total	$219.5	($993.2)	$61.5	$1,274.2	$9.0	($6.0)	($30.0)	($15.0)	$1,259.2

Table 2-88 Monthly marginal loss costs by control zone (Dollars (Millions)): January through September 2010 (See 2009 SOM, Table 2-81)

	Marginal Loss Costs by Control Zone (Millions)									
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Grand Total
AECO	$2.6	$1.5	$1.4	$1.4	$1.6	$3.3	$6.7	$4.1	$2.1	$24.8
AEP	$40.0	$25.9	$16.4	$13.8	$14.8	$31.5	$53.5	$37.8	$19.2	$252.8
AP	$13.7	$11.2	$6.8	$6.5	$8.4	$11.3	$16.7	$12.0	$6.9	$93.7
BGE	$8.8	$6.7	$3.7	$3.3	$4.8	$7.3	$11.3	$7.8	$5.0	$58.6
ComEd	$36.1	$23.9	$19.8	$16.2	$16.9	$23.7	$32.0	$26.4	$23.0	$217.9
DAY	$6.6	$5.3	$4.2	$2.6	$4.6	$5.6	$9.7	$6.7	$4.6	$50.0
DLCO	$3.0	$2.3	$1.6	$1.3	$1.4	$1.5	$1.7	$1.3	$1.3	$15.5
Dominion	$20.1	$15.9	$9.0	$8.9	$10.8	$21.0	$28.6	$20.2	$13.1	$147.5
DPL	$5.7	$3.6	$2.6	$2.8	$3.2	$4.7	$8.5	$6.0	$4.4	$41.5
JCPL	$6.3	$4.0	$3.3	$2.3	$3.3	$5.1	$8.2	$4.9	$3.0	$40.5
Met-Ed	$2.8	$1.6	$1.4	$1.0	$1.4	$2.1	$2.3	$2.1	$1.3	$16.0
PECO	$4.2	$3.7	$2.3	$1.9	$3.6	$7.1	$9.3	$6.9	$4.4	$43.4
PENELEC	$10.4	$7.2	$3.6	$3.6	$5.8	$8.6	$11.1	$8.9	$8.0	$67.2
Pepco	$6.7	$5.7	$4.5	$3.8	$5.0	$6.4	$9.1	$6.0	$4.2	$51.3
PJM	$5.5	$3.7	$2.9	$2.4	$5.2	$3.2	$1.6	$1.8	$1.2	$27.6
PPL	$8.8	$6.3	$3.7	$2.2	$3.2	$5.4	$6.2	$6.3	$5.2	$47.2
PSEG	$7.0	$5.4	$5.8	$4.3	$5.3	$7.9	$10.4	$7.7	$5.8	$59.7
RECO	$0.5	$0.2	$0.2	$0.2	$0.3	$0.5	$0.8	$0.5	$0.4	$3.7
Total	$188.9	$134.3	$93.4	$78.4	$99.6	$156.3	$227.9	$167.3	$113.1	$1,259.2

Virtual Offers and Bids

Table 2-89 Monthly volume of cleared and submitted INCs, DECs: January through September 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	11,276	23,414	250	1,585	17,223	25,690	304	1,284
Aug	10,567	20,751	226	1,332	15,656	21,745	327	1,140
Sep	10,944	21,365	263	1,232	15,522	22,646	311	1,072
Oct								
Nov								
Dec								
Annual	11,137	21,611	274	1,134	16,174	25,539	273	976

Table 2-90 Type of day-ahead marginal units: January through September 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%
Jul	12.5%	40.7%	24.3%	21.7%	0.9%
Aug	11.1%	52.5%	17.7%	17.8%	0.9%
Sep	12.6%	43.8%	23.2%	18.4%	0.4%
Annual	12.9%	37.4%	27.3%	21.7%	0.6%

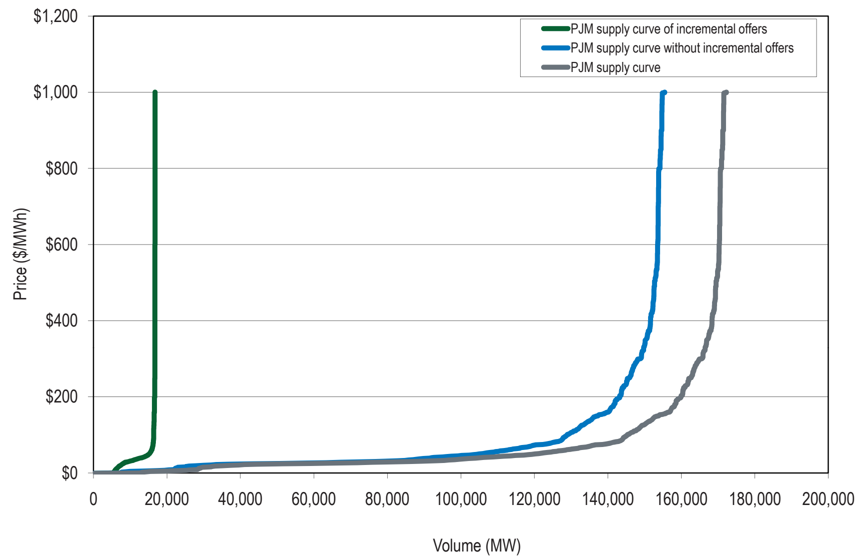
Table 2-91 PJM virtual bids by type of bid parent organization (MW): January through September 2010 (See 2009 SOM, Table 2-84)

	Category	Total Virtual Bids MW	Percentage
2010	Financial	98,859,787	32.0%
2010	Physical	210,016,261	68.0%
2010	Total	308,876,049	100.0%

Table 2-92 PJM virtual bids by top ten locations (MW): January through September 2010 (See 2009 SOM, Table 2-85)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	45,935,725	52,987,976	98,923,702
N ILLINOIS HUB	HUB	8,130,610	8,302,430	16,433,040
AEP-DAYTON HUB	HUB	4,500,957	5,745,609	10,246,566
PSEG	ZONE	2,099,900	4,656,424	6,756,324
PPL	ZONE	395,988	6,247,001	6,642,988
Pepco	ZONE	5,157,391	1,000,756	6,158,147
BGE	ZONE	3,175,589	2,702,532	5,878,121
JCPL	ZONE	3,412,010	2,038,140	5,450,150
MISO	INTERFACE	1,040,035	2,811,361	3,851,396
ComEd	ZONE	1,607,186	1,460,892	3,068,078

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



Price Convergence

Table 2-93 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-86)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$45.81	$46.13	$0.32	0.7%
Median	$41.03	$37.89	($3.14)	(8.3%)
Standard deviation	$19.59	$26.99	$7.39	27.4%

Table 2-94 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 through September 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	$45.81	$46.13	$0.32	0.7%

Table 2-95 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2006 through September 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%	13	0.20%
($50) to $0	5,205	59.54%	4,600	52.89%	5,120	59.30%	5,108	58.34%	4,091	62.65%
$0 to $50	3,372	98.04%	3,827	96.58%	3,247	96.27%	3,603	99.47%	2,288	97.57%
$50 to $100	152	99.77%	255	99.49%	284	99.50%	41	99.94%	130	99.56%
$100 to $150	9	99.87%	31	99.84%	37	99.92%	5	100.00%	20	99.86%
$150 to $200	4	99.92%	5	99.90%	4	99.97%	0	100.00%	8	99.98%
$200 to $250	1	99.93%	1	99.91%	2	99.99%	0	100.00%	1	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 September 2010 (See 2009 SOM, Figure 2-20)

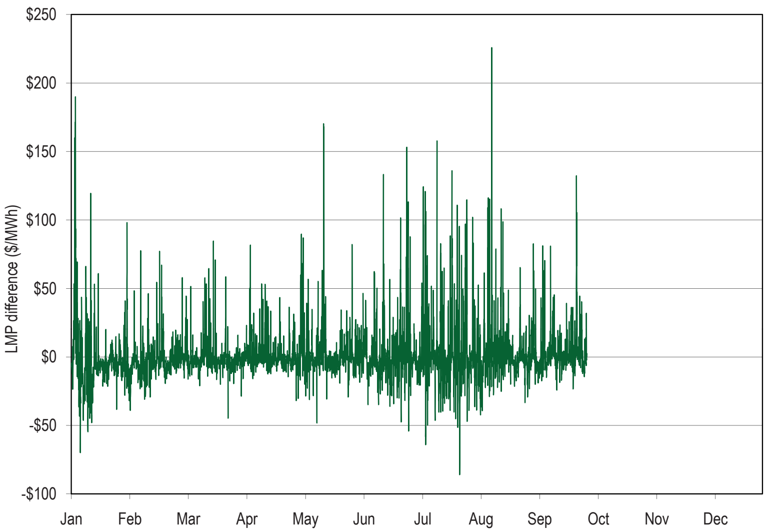


Figure 2-23 Monthly simple average of real-time minus day-ahead LMP: January through September 2010 (See 2009 SOM, Figure 2-21)

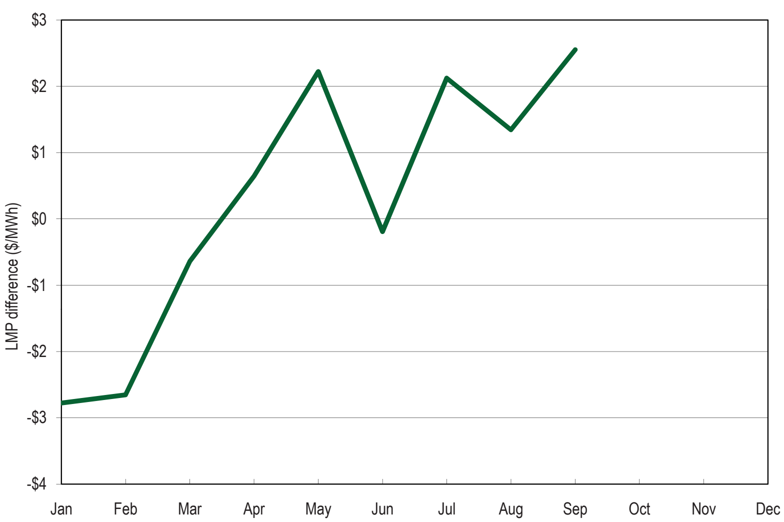
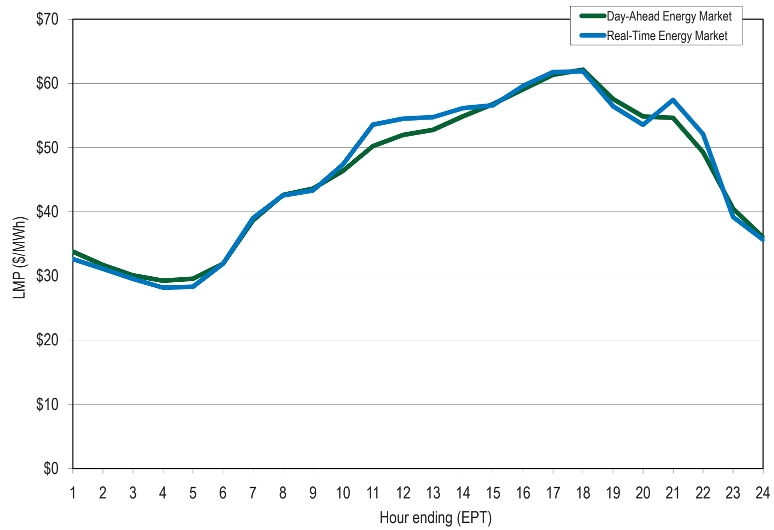


Figure 2-24 PJM system simple hourly average LMP: January through September 2010 (See 2009 SOM, Figure 2-22)



Zonal Price Convergence

Table 2-96 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-89)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$51.79	$52.40	$0.61	1.2%
AEP	$39.00	$39.13	$0.13	0.3%
AP	$45.16	$45.30	$0.13	0.3%
BGE	$54.65	$55.05	$0.40	0.7%
ComEd	$35.29	$35.31	$0.03	0.1%
DAY	$38.85	$39.16	$0.31	0.8%
DLCO	$38.90	$38.17	($0.73)	(1.9%)
Dominion	$52.22	$52.11	($0.11)	(0.2%)
DPL	$52.02	$52.64	$0.62	1.2%
JCPL	$51.29	$51.17	($0.12)	(0.2%)
Met-Ed	$50.59	$50.90	$0.31	0.6%
PECO	$50.90	$50.71	($0.19)	(0.4%)
PENELEC	$44.39	$43.38	($1.01)	(2.3%)
Pepco	$54.25	$54.04	($0.21)	(0.4%)
PPL	$49.05	$49.23	$0.17	0.4%
PSEG	$52.04	$52.03	($0.01)	(0.0%)
RECO	$50.86	$50.14	($0.71)	(1.4%)

Price Convergence by Jurisdiction

Table 2-97 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-90)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$50.94	$51.69	$0.76	1.5%
Illinois	$35.29	$35.31	$0.03	0.1%
Indiana	$38.26	$38.36	$0.09	0.2%
Kentucky	$39.08	$39.32	$0.24	0.6%
Maryland	$54.46	$54.51	$0.05	0.1%
Michigan	$38.87	$39.05	$0.18	0.5%
New Jersey	$51.79	$51.82	$0.03	0.1%
North Carolina	$50.39	$50.13	($0.26)	(0.5%)
Ohio	$38.20	$38.47	$0.27	0.7%
Pennsylvania	$47.46	$47.32	($0.14)	(0.3%)
Tennessee	$40.05	$40.06	$0.01	0.0%
Virginia	$50.86	$50.55	($0.31)	(0.6%)
West Virginia	$39.69	$39.82	$0.13	0.3%
District of Columbia	$54.28	$54.21	($0.07)	(0.1%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-98 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2009 to September 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%	9.8%	19.7%	70.6%	(2.8%)	2.7%	0.1%
Aug	11.7%	16.0%	72.3%	10.5%	20.7%	68.8%	(1.2%)	4.7%	(3.5%)
Sep	12.5%	18.1%	69.4%	12.0%	22.4%	65.6%	(0.5%)	4.3%	(3.8%)
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%	11.5%	19.4%	69.1%	(1.3%)	2.4%	(1.0%)

Day-Ahead Load and Spot Market

Table 2-99 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2009 to September 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%	4.7%	18.9%	76.5%	(0.9%)	2.9%	(1.9%)
Aug	5.2%	15.3%	79.5%	4.7%	19.6%	75.7%	(0.4%)	4.3%	(3.9%)
Sep	4.8%	16.1%	79.2%	4.5%	20.9%	74.6%	(0.2%)	4.8%	(4.6%)
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%	4.8%	18.9%	76.3%	(0.1%)	4.1%	(4.0%)

Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-100 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 2-101 Economic Program registration on peak load days: Calendar years 2002 to 2009 and January through September 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
06-Jul-10	899	1,725.7

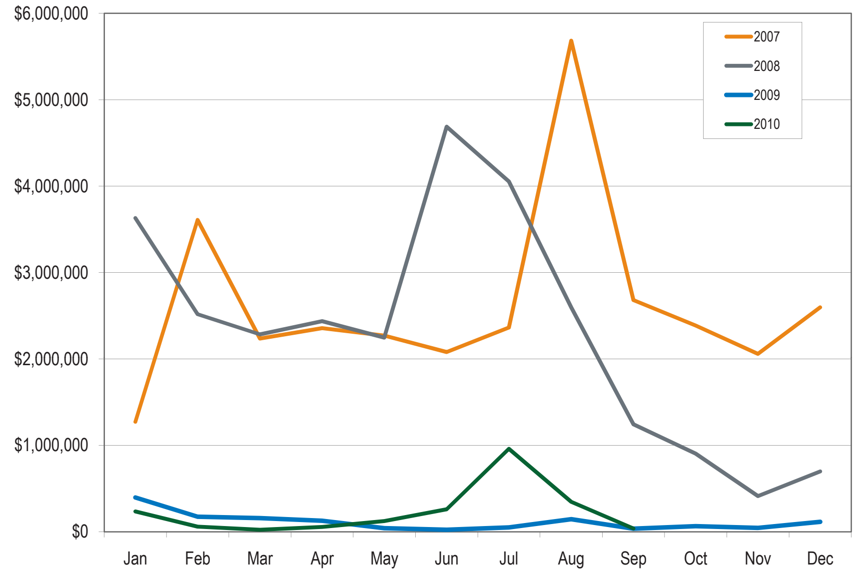
Table 2-102 Economic Program registrations on the last day of the month: January 2007 through September 2010 (See 2009 SOM, Table 2-95)

	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	2,587
May	996	3,674	5,069	3,588	1,250	2,860	1,875	2,587
Jun	2,490	2,168	3,112	3,014	1,265	2,461	813	1,608
Jul	2,872	2,459	4,542	3,165	1,265	2,445	1,192	2,159
Aug	2,911	2,582	4,815	3,232	1,653	2,650	1,616	2,398
Sep	4,868	2,915	4,836	3,263	1,879	2,727	1,849	2,587
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 2-103 Distinct registrations and sites in the Economic Program: July 6, 2010[13] (See 2009 SOM, Table 2-96)

	Registrations	Sites	MW
AECO	32	33	14.6
AEP	45	45	52.3
AP	53	55	185.0
BGE	62	63	476.0
ComEd	75	76	111.7
DAY	8	8	10.5
DLCO	89	89	199.3
Dominion	37	40	97.7
DPL	31	31	72.8
JCPL	40	43	100.9
Met-Ed	49	51	55.3
PECO	136	137	116.9
PENELEC	48	49	35.4
Pepco	26	26	26.9
PPL	114	119	144.3
PSEG	53	94	25.7
RECO	1	1	0.3
Total	899	960	1,725.7

Figure 2-25 Economic Program payments: Calendar years 2007[14] through 2009 and January through September 2010[15] (See 2009 SOM, Figure 2-24)



13 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.

14 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.

15 September 2010 credits and settlement counts 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 2-104 PJM Economic Program by zonal reduction: January through September 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	9	$406	8				78	$4,620	79	87	$5,026	87
AEP												
AP	3,555	$102,800	960				110	$11,535	39	3,665	$114,335	999
BGE	1,806	$300,724	251				1,873	$145,183	232	3,679	$445,908	483
ComEd	121	$3,614	121				2,166	$36,168	986	2,286	$39,782	1,107
DAY	0	$8	2				11	$1,165	1	11	$1,173	3
DLCO	9,627	$732,702	724	4,096	$98,936	212	953	$45,988	1,095	14,676	$877,626	2,031
Dominion	1	$248	10							1	$248	10
DPL												
JCPL	88	$15,426	16				35	$2,155	130	123	$17,581	146
Met-Ed	21	$310	22							21	$310	22
PECO	18,983	$543,396	17,020				455	$43,631	1,803	19,439	$587,027	18,823
PENELEC	20	$85	30				3	$273	14	23	$358	44
Pepco	28	$1,564	75				30	$1,542	132	58	$3,106	207
PPL	424	$11,273	408	3	$407	11	51	$3,558	225	478	$15,239	644
PSEG	61	$1,458	114							61	$1,458	114
RECO												
Total	34,744	$1,714,014	19,761	4,099	$99,343	223	5,766	$295,819	4,736	44,610	$2,109,176	24,720
Max	18,983	$732,702	17,020	4,096	$98,936	212	2,166	$145,183	1,803	19,439	$877,626	18,823
Avg	2,482	$122,430	1,412	2,050	$49,672	112	524	$26,893	431	3,186	$150,655	1,766

Table 2-105 Settlement days submitted by month in the Economic Program: January 2007 through September 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	673
Jun	1,856	3,184	2,727	1,221
Jul	2,534	3,339	2,879	3,007
Aug	3,962	3,848	3,760	2,158
Sep	3,388	3,264	2,570	660
Oct	3,508	1,977	2,361	
Nov	2,842	1,105	2,321	
Dec	2,675	986	1,240	
Total	26,423	32,990	21,605	10,437

Table 2-106 Distinct customers and CSPs submitting settlements in the Economic Program by month: January 2007 through September 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	6	140
Jun	12	195	17	317	20	231	11	152
Jul	15	259	16	295	21	183	18	243
Aug	19	321	17	306	15	400	14	302
Sep	15	279	17	312	11	181	11	97
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	24	433

Table 2-107 Hourly distribution of Economic Program MWh reductions and credits: January through September 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	280	0.63%	280	0.63%	$4,500	0.21%	$4,500	0.21%
2	299	0.67%	579	1.30%	$4,149	0.20%	$8,649	0.41%
3	348	0.78%	927	2.08%	$3,639	0.17%	$12,288	0.58%
4	360	0.81%	1,287	2.88%	$4,573	0.22%	$16,861	0.80%
5	390	0.87%	1,677	3.76%	$3,573	0.17%	$20,434	0.97%
6	423	0.95%	2,100	4.71%	$4,785	0.23%	$25,219	1.20%
7	1,027	2.30%	3,126	7.01%	$41,329	1.96%	$66,548	3.16%
8	1,634	3.66%	4,760	10.67%	$83,204	3.94%	$149,751	7.10%
9	1,838	4.12%	6,598	14.79%	$51,918	2.46%	$201,670	9.56%
10	1,705	3.82%	8,302	18.61%	$44,545	2.11%	$246,215	11.67%
11	1,605	3.60%	9,908	22.21%	$48,128	2.28%	$294,343	13.96%
12	1,743	3.91%	11,651	26.12%	$60,989	2.89%	$355,332	16.85%
13	2,018	4.52%	13,669	30.64%	$79,765	3.78%	$435,097	20.63%
14	2,545	5.70%	16,214	36.35%	$146,216	6.93%	$581,313	27.56%
15	4,209	9.44%	20,423	45.78%	$211,267	10.02%	$792,579	37.58%
16	4,678	10.49%	25,101	56.27%	$366,018	17.35%	$1,158,597	54.93%
17	5,075	11.38%	30,175	67.64%	$360,991	17.12%	$1,519,588	72.05%
18	4,991	11.19%	35,167	78.83%	$277,704	13.17%	$1,797,293	85.21%
19	2,465	5.53%	37,632	84.36%	$97,733	4.63%	$1,895,025	89.85%
20	1,876	4.21%	39,508	88.56%	$66,921	3.17%	$1,961,947	93.02%
21	1,556	3.49%	41,063	92.05%	$67,125	3.18%	$2,029,072	96.20%
22	1,507	3.38%	42,570	95.43%	$48,151	2.28%	$2,077,223	98.49%
23	1,164	2.61%	43,735	98.04%	$18,722	0.89%	$2,095,945	99.37%
24	875	1.96%	44,610	100.00%	$13,231	0.63%	$2,109,176	100.00%

Table 2-108 Distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through September 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	210	0.47%	210	0.47%	$232	0.01%	$232	0.01%
$25 to $50	15,977	35.82%	16,188	36.29%	$193,688	9.18%	$193,919	9.19%
$50 to $75	7,679	17.21%	23,866	53.50%	$200,571	9.51%	$394,491	18.70%
$75 to $100	4,648	10.42%	28,514	63.92%	$191,284	9.07%	$585,774	27.77%
$100 to $125	4,649	10.42%	33,163	74.34%	$193,193	9.16%	$778,968	36.93%
$125 to $150	3,968	8.89%	37,131	83.24%	$242,005	11.47%	$1,020,973	48.41%
$150 to $200	3,928	8.80%	41,059	92.04%	$401,654	19.04%	$1,422,626	67.45%
$200 to $250	1,437	3.22%	42,495	95.26%	$227,764	10.80%	$1,650,391	78.25%
$250 to $300	913	2.05%	43,408	97.31%	$154,887	7.34%	$1,805,278	85.59%
> $300	1,202	2.69%	44,610	100.00%	$303,899	14.41%	$2,109,176	100.00%

Emergency Program

Table 2-109 Registered sites and MW in the Emergency Program[16] (By zone and option): July 6, 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	7	12.1
AEP	0	0.0	688	1,039.1	164	674.9
AP	0	0.0	672	612.0	100	156.8
BGE	0	0.0	441	758.1	28	79.3
ComEd	0	0.0	899	949.9	582	513.5
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	33	84.6
DPL	0	0.0	174	140.8	18	36.8
JCPL	0	0.0	206	161.0	17	15.2
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	29	13.8
Pepco	0	0.0	265	177.8	27	33.8
PPL	0	0.0	643	671.2	84	56.1
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	1,472	1,999.9

Table 2-110 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	893.4	7,982.4	8,875.9

16 Table 2-109 shows registered sites and MW in the Emergency Program as of July 6, 2010, the peak load day through the first nine 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 2-110 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 2-111 Zonal monthly capacity credits: January 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-106)

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$538,827	$486,683	$387,589	$521,446	$538,827	$498,630	$515,251	$515,251	$498,630	$4,501,133
AEP	$3,871,619	$3,496,946	$3,871,619	$3,746,728	$3,871,619	$7,469,753	$7,718,744	$7,718,744	$7,469,753	$49,235,524
APS	$3,380,342	$3,053,212	$3,082,016	$3,271,298	$3,380,342	$4,134,986	$4,272,819	$4,272,819	$4,134,986	$32,982,821
BGE	$4,971,814	$4,490,671	$4,613,517	$4,811,433	$4,971,814	$4,877,253	$5,039,828	$5,039,828	$4,877,253	$43,693,412
ComEd	$4,423,355	$3,995,288	$4,357,876	$4,280,666	$4,423,355	$7,893,843	$8,156,971	$8,156,971	$7,893,843	$53,582,167
DAY	$667,966	$603,324	$667,966	$646,419	$667,966	$1,114,399	$1,151,545	$1,151,545	$1,114,399	$7,785,530
DLCO	$387,642	$350,129	$387,642	$375,138	$387,642	$1,082,462	$1,118,544	$1,118,544	$1,082,462	$6,290,206
Dominion	$1,655,820	$1,495,580	$1,655,820	$1,602,407	$1,655,820	$5,271,768	$5,447,494	$5,447,494	$5,271,768	$29,503,972
DPL	$1,117,919	$1,009,733	$1,004,045	$1,081,857	$1,117,919	$1,053,129	$1,088,233	$1,088,233	$1,053,129	$9,614,195
JCPL	$1,374,149	$1,241,167	$897,896	$1,329,822	$1,374,149	$1,259,066	$1,301,034	$1,301,034	$1,259,066	$11,337,383
Met-Ed	$1,357,392	$1,226,031	$1,357,392	$1,313,605	$1,357,392	$1,166,215	$1,205,089	$1,205,089	$1,166,215	$11,354,420
PECO	$2,717,550	$2,454,561	$2,120,899	$2,629,887	$2,717,550	$2,735,060	$2,826,229	$2,826,229	$2,735,060	$23,763,024
PENELEC	$1,325,705	$1,197,411	$1,325,705	$1,282,941	$1,325,705	$1,768,655	$1,827,610	$1,827,610	$1,768,655	$13,649,996
Pepco	$1,161,239	$1,048,861	$814,714	$1,123,780	$1,161,239	$1,265,186	$1,307,359	$1,307,359	$1,265,186	$10,454,922
PPL	$3,583,739	$3,236,926	$3,617,545	$3,468,134	$3,583,739	$3,982,417	$4,115,164	$4,115,164	$3,982,417	$33,685,245
PSEG	$2,266,920	$2,047,540	$1,777,619	$2,193,793	$2,266,920	$2,454,980	$2,536,813	$2,536,813	$2,454,980	$20,536,379
RECO	$24,425	$22,061	$18,494	$23,637	$24,425	$8,967	$9,266	$9,266	$8,967	$149,507
Total	$34,826,423	$31,456,124	$31,958,354	$33,702,990	$34,826,423	$48,036,768	$49,637,993	$49,637,993	$48,036,768	$362,119,835

Table 2-112 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007/2008 through 2013/2014 (See 2009 SOM, Table 2-107)

Delivery 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 nine 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 nine months of 2010, total net revenues were higher compared to the same period in 2009. The increases in total net revenues by technology type are the result of increases in energy revenues, resulting from higher energy prices, and in most cases, increases in capacity revenues, resulting from capacity prices determined in 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, all zones had higher total net revenue in the first nine months of 2010 compared to the same period in 2009. (See Table 3-8.) For the new entrant CT, all zones had higher energy net revenue. All zones but two, BGE and Pepco, had higher capacity revenues. The 2010/2011 Base Residual Auction (BRA) cleared with much less price separation by location than prior delivery years, and at a higher price for the RTO Locational Deliverability Area (LDA) than previous BRAs. As a result, zones that previously cleared in constrained LDAs saw slight increases or, in the case of SWMAAC, decreases, in capacity revenue for calendar year 2010, while zones that previously cleared in the unconstrained RTO LDA saw significant increases in capacity revenue. The BGE and Pepco zones, which previously cleared in the SWMAAC LDA for the 2009/2010 delivery year, had a lower clearing price associated with the unconstrained RTO LDA for the 2010/2011 delivery year. The decreases in capacity revenue were more than offset by increases in energy net revenue. The six zones that were part of the MAAC+APS LDA for the 2009/2010 BRA and which previously cleared in the EMAAC LDA had slightly higher capacity revenues. Of these six zones, DPL showed a larger increase as DPL South separated and cleared at a slightly higher price than the RTO LDA in the 2010/2011 BRA. The five zones that had cleared in the unconstrained RTO LDA for the 2009/2010 delivery year had significantly higher capacity revenues as a result of higher capacity prices for the 2010/2011 delivery year. The four zones that cleared in the MAAC+APS LDA and that had cleared with the unconstrained RTO LDA in the 2008/2009 BRA, had significantly higher capacity revenues associated with the constrained MAAC+APS LDA in the 2009/2010 delivery year, but slightly lower capacity revenues associated with the 2010/2011 delivery year, thus the rate of increase in capacity revenue will fall through calendar year 2010.

For the new entrant CC, all zones had higher total net revenue in the first nine months of 2010 compared to the same period in 2009. (See Table 3-10.) For the new entrant CC, all zones showed an increase in energy net revenue. For the two SWMAAC zones, higher energy net revenue more than offset decreases in capacity revenues.

For the new entrant coal plant (CP), all seventeen zones had higher total net revenue in the first nine months of 2010 compared to the same period in 2009. (See Table 3-12.) For the CP, all zones showed an increase in energy net revenues. For the two SWMAAC 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 September 30, 2010, PJM installed capacity resources fell slightly from 167,853.8 MW on January 1 to 166,732.1 MW on September 30, a decrease of 1,121.7 MW or 0.7 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of September 30, 2010, 41.0 percent was coal; 28.7 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 nine months of 2010, coal provided 49.9 percent, nuclear 34.3 percent, gas 11.4 percent, oil 0.5 percent, hydroelectric 2.0 percent, solid waste 0.8 percent and wind 1.0 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.

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 Nine Months of 2010.** The level of operating reserve credits and corresponding charges increased in the first nine months of 2010 by 67.1 percent compared to the first nine months of 2009. The largest increase occurred in the third quarter of 2010, which was 116.7 percent higher than the third quarter 2009. 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 6.6 percent, or $4,480,596, decrease in the amount of day-ahead credits, a 73.3 percent, or $1,725,912, decrease in synchronous condensing credits, and a 98.0 percent, or $169,638,134, increase in balancing credits. The increase in balancing credits can be attributed primarily to the large increase in demand in the summer of 2010. Balancing operating reserve credits in each month of the summer in 2010 were more than double the levels in the summer months of 2009. In particular, increased Eastern reliability credits accounted for much of the increase. Total operating reserve credits for the first nine months of 2010 were higher than for the full year of 2009 by $81,036,135.

- **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 first nine months of 2010. The new operating reserve rules resulted in an increase of $82,450,015 in charges assigned to real-time load and exports for the first nine months of 2010. These increases were matched by a decrease of $46,020,429 in charges to demand deviations, a decrease of $22,590,700 in charges to supply deviations, and a decrease of $13,838,886 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 $26,689,574 less in operating reserve charges in the first nine months of 2010 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 $14,909,560, or 6.9 percent, higher for the first nine months of 2010 than they would have been under the old rules, and a total of $23,083,966 higher since December 2008. The most significant difference since the new rule went into effect was for July 2010, when the increase in payments due to the rule change was $4,801,974.

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 third quarter of 2010 showed a continuation of trends noted in the second quarter of 2010 when compared to the same time period in the prior year. In the third 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 third 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 third quarter compared to the same period in 2009.

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. All zones had more high demand days in the third quarter of 2010 compared to 2009 and all zones showed a higher frequency of hours of real-time LMP greater than $200. The average on peak LMP for PJM increased 61 percent in the third quarter of 2010 compared to the same period in 2009, while in RECO and in PSEG, average on peak LMP increased by 80 and 82 percent. The PJM average real-time LMP was greater than $200 for thirteen hours in the third quarter of 2010, compared to zero hours in the same period for 2009. In RECO and PSEG, Real-Time LMP was greater than $200 for 36 hours and 42 hours in the third quarter of 2010, compared to zero hours in both zones for the same period in 2009. As a result, the average increase in energy net revenue for a new entrant CT was 257 percent, and the RECO and PSEG zones show increases of 357 and 338 percent.

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 nine months of 2010, particularly in the third quarter, 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 (Jan - Dec)
Zone	LDA	$/MW-Day	$/MW in 2010	LDA	$/MW-Day	$/MW in 2010	$/MW
AECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
AEP	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
AP	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
BGE	SWMAAC	$237.33	$35,837	RTO	$174.29	$37,298	$73,135
ComEd	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DAY	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DLCO	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
Dominion	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DPL	MAAC+APS	$191.32	$28,889	DPL South	$178.57	$38,214	$67,103
JCPL	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
Met-Ed	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PENELEC	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
Pepco	SWMAAC	$237.33	$35,837	RTO	$174.29	$37,298	$73,135
PPL	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PSEG	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
RECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PJM	NA	$154.47	$23,325	NA	$174.42	$37,327	$60,652

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

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$45,810	$50,153	9%
AEP	$29,349	$36,671	25%
AP	$40,241	$50,153	25%
BGE	$60,681	$57,100	(6%)
ComEd	$29,349	$36,671	25%
DAY	$29,349	$36,671	25%
DLCO	$29,349	$36,671	25%
Dominion	$29,349	$36,671	25%
DPL	$45,810	$50,675	11%
JCPL	$45,810	$50,153	9%
Met-Ed	$40,241	$50,153	25%
PECO	$45,810	$50,153	9%
PENELEC	$40,241	$50,153	25%
Pepco	$60,681	$57,100	(6%)
PPL	$40,241	$50,153	25%
PSEG	$45,810	$50,153	9%
RECO	$45,810	$50,153	9%
PJM	$38,259	$44,605	17%

New Entrant Net Revenues

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

	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
Natural Gas	$4.43	$5.08	15%
Delivered Coal	$3.14	$2.74	(13%)

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.

Table 3-4 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 September 2009 and 2010 (See 2009 SOM, Table 3-6)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$10,047	$43,619	334%
AEP	$3,142	$8,892	183%
AP	$11,985	$24,634	106%
BGE	$12,879	$54,012	319%
ComEd	$2,387	$8,380	251%
DAY	$2,893	$9,075	214%
DLCO	$3,919	$13,719	250%
Dominion	$12,580	$43,343	245%
DPL	$12,674	$42,258	233%
JCPL	$10,229	$37,989	271%
Met-Ed	$9,332	$40,109	330%
PECO	$8,902	$37,115	317%
PENELEC	$5,679	$16,404	189%
Pepco	$20,330	$55,160	171%
PPL	$8,336	$34,282	311%
PSEG	$8,604	$37,681	338%
RECO	$7,303	$33,384	357%
PJM	$8,895	$31,768	257%

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 September 2009 and 2010 (See 2009 SOM, Table 3-7)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$42,470	$91,595	116%
AEP	$22,459	$35,377	58%
AP	$46,639	$65,079	40%
BGE	$46,652	$106,577	128%
ComEd	$17,755	$30,535	72%
DAY	$22,421	$36,291	62%
DLCO	$22,172	$37,762	70%
Dominion	$46,667	$92,196	98%
DPL	$46,230	$92,016	99%
JCPL	$43,472	$85,526	97%
Met-Ed	$38,889	$86,006	121%
PECO	$39,121	$83,181	113%
PENELEC	$33,676	$50,629	50%
Pepco	$60,297	$110,451	83%
PPL	$36,642	$77,152	111%
PSEG	$41,012	$85,855	109%
RECO	$37,148	$77,871	110%
PJM	$37,866	$73,182	93%

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 3-6 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 September 2009 and 2010 (See 2009 SOM, Table 3-8)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$70,368	$143,499	104%
AEP	$20,467	$81,501	298%
AP	$46,693	$110,639	137%
BGE	$37,648	$157,876	319%
ComEd	$38,003	$100,098	163%
DAY	$28,063	$69,265	147%
DLCO	$24,481	$64,155	162%
Dominion	$41,757	$130,382	212%
DPL	$34,678	$124,961	260%
JCPL	$62,202	$133,130	114%
Met-Ed	$50,390	$128,414	155%
PECO	$63,780	$132,550	108%
PENELEC	$63,978	$88,447	38%
Pepco	$59,400	$146,130	146%
PPL	$59,672	$123,262	107%
PSEG	$82,573	$138,054	67%
RECO	$59,622	$127,010	113%
PJM	$49,634	$117,610	137%

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 September 2010 (See 2009 SOM, Table 3-9)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
Energy	$8,895	$31,768	257%
Capacity	$34,096	$40,214	18%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,799	$1,799	0%
Total	$44,789	$73,781	65%

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 September 2009 and 2010 (See 2009 SOM, Table 3-10)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$52,670	$90,633	72%
AEP	$31,095	$43,752	41%
AP	$49,645	$71,647	44%
BGE	$68,755	$107,289	56%
ComEd	$30,340	$43,240	43%
DAY	$30,846	$43,935	42%
DLCO	$31,872	$48,579	52%
Dominion	$40,533	$78,203	93%
DPL	$55,297	$89,742	62%
JCPL	$52,852	$85,003	61%
Met-Ed	$46,992	$87,123	85%
PECO	$51,525	$84,129	63%
PENELEC	$43,339	$63,418	46%
Pepco	$76,206	$108,437	42%
PPL	$45,996	$81,295	77%
PSEG	$51,227	$84,695	65%
RECO	$49,926	$80,398	61%
PJM	$44,789	$73,781	65%

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 September 2010 (See 2009 SOM, Table 3-11)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
Energy	$37,866	$73,182	93%
Capacity	$36,961	$42,906	16%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$2,399	$2,399	0%
Total	$77,226	$118,487	53%

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 September 2009 and 2010 (See 2009 SOM, Table 3-12)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$89,124	$142,236	60%
AEP	$53,211	$73,050	37%
AP	$87,914	$115,720	32%
BGE	$107,673	$163,901	52%
ComEd	$48,506	$68,208	41%
DAY	$53,172	$73,964	39%
DLCO	$52,924	$75,436	43%
Dominion	$77,418	$129,869	68%
DPL	$92,884	$143,159	54%
JCPL	$90,126	$136,167	51%
Met-Ed	$80,163	$136,647	70%
PECO	$85,775	$133,822	56%
PENELEC	$74,950	$101,270	35%
Pepco	$121,317	$167,775	38%
PPL	$77,916	$127,793	64%
PSEG	$87,666	$136,496	56%
RECO	$83,802	$128,512	53%
PJM	$77,226	$118,487	53%

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 September 2010 (See 2009 SOM, Table 3-13)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
Energy	$49,634	$117,610	137%
Capacity	$34,493	$40,452	17%
Synchronized	$0	$0	0%
Regulation	$204	$0	(100%)
Reactive	$1,337	$1,337	0%
Total	$85,668	$159,400	86%

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 September 2009 and 2010 (See 2009 SOM, Table 3-14)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$113,359	$190,550	68%
AEP	$48,497	$116,363	140%
AP	$84,577	$157,748	87%
BGE	$93,822	$211,232	125%
ComEd	$66,675	$135,076	103%
DAY	$56,483	$104,022	84%
DLCO	$52,548	$98,900	88%
Dominion	$69,711	$165,122	137%
DPL	$77,436	$172,408	123%
JCPL	$105,112	$180,159	71%
Met-Ed	$88,210	$175,406	99%
PECO	$106,716	$179,597	68%
PENELEC	$102,672	$135,434	32%
Pepco	$115,660	$199,420	72%
PPL	$97,567	$170,273	75%
PSEG	$126,080	$185,101	47%
RECO	$102,517	$174,045	70%
PJM	$85,668	$159,611	86%

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 September 2009 and 2010 (See 2009 SOM, Table 3-15)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$5,455	$28,044	414%
AEP	$875	$5,248	500%
AP	$4,529	$16,664	268%
BGE	$6,260	$36,429	482%
ComEd	$334	$5,232	1,465%
DAY	$496	$5,649	1,039%
DLCO	$894	$7,787	771%
Dominion	$6,231	$28,842	363%
DPL	$5,893	$26,786	355%
JCPL	$4,146	$25,086	505%
Met-Ed	$3,867	$26,229	578%
PECO	$4,150	$24,909	500%
PENELEC	$2,695	$12,031	346%
Pepco	$13,751	$40,735	196%
PPL	$3,634	$21,408	489%
PSEG	$3,357	$24,278	623%
RECO	$2,556	$22,245	770%
PJM	$4,066	$21,035	417%

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 September 2009 and 2010 (See 2009 SOM, Table 3-16)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$40,074	$80,094	100%
AEP	$17,190	$31,179	81%
AP	$38,367	$60,594	58%
BGE	$42,834	$95,595	123%
ComEd	$10,844	$25,707	137%
DAY	$15,470	$31,437	103%
DLCO	$14,990	$35,496	137%
Dominion	$43,095	$85,103	97%
DPL	$41,414	$80,507	94%
JCPL	$39,691	$78,601	98%
Met-Ed	$34,468	$76,302	121%
PECO	$36,469	$76,224	109%
PENELEC	$30,100	$51,544	71%
Pepco	$56,952	$104,736	84%
PPL	$32,838	$67,923	107%
PSEG	$37,348	$77,442	107%
RECO	$32,850	$71,938	119%
PJM	$33,235	$66,495	100%

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 September 2009 and 2010 (See 2009 SOM, Table 3-17)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$72,861	$139,420	91%
AEP	$16,497	$79,880	384%
AP	$40,888	$109,447	168%
BGE	$37,183	$155,210	317%
ComEd	$34,132	$98,843	190%
DAY	$23,161	$66,433	187%
DLCO	$18,006	$63,561	253%
Dominion	$40,187	$130,450	225%
DPL	$32,571	$120,643	270%
JCPL	$62,547	$133,242	113%
Met-Ed	$49,372	$125,874	155%
PECO	$66,233	$133,051	101%
PENELEC	$65,455	$93,398	43%
Pepco	$59,214	$146,901	148%
PPL	$60,302	$121,401	101%
PSEG	$85,230	$137,643	61%
RECO	$59,593	$130,588	119%
PJM	$48,437	$116,823	141%

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 September 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 - Sep)	$31,768	$21,035	$10,733	34%

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 September 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 - Sep)	$73,182	$66,495	$6,687	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 September 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 - Sep)	$117,610	$116,823	$787	1%

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

New Entrant Combustion Turbine

Figure 3-1 New entrant CT zonal real-time 2010 net revenue by market for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (New Figure)

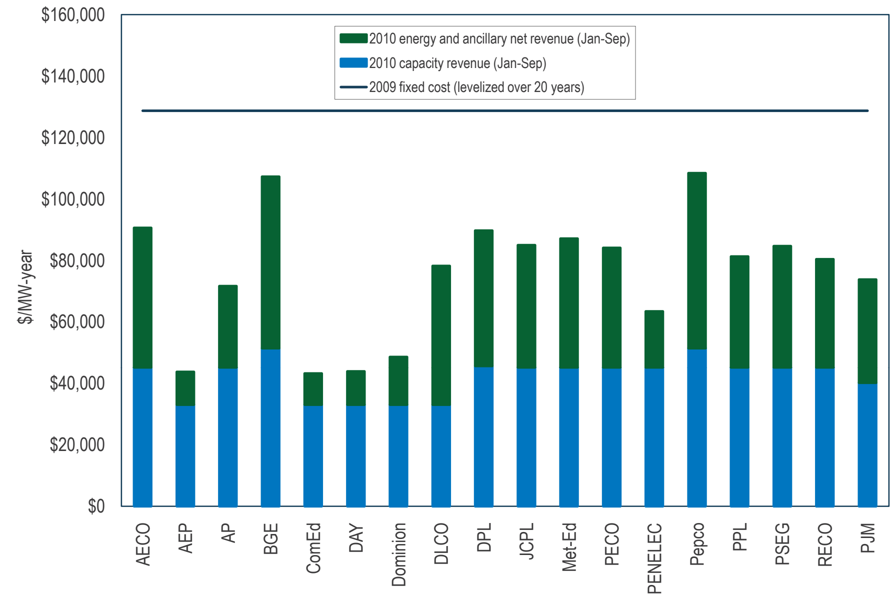
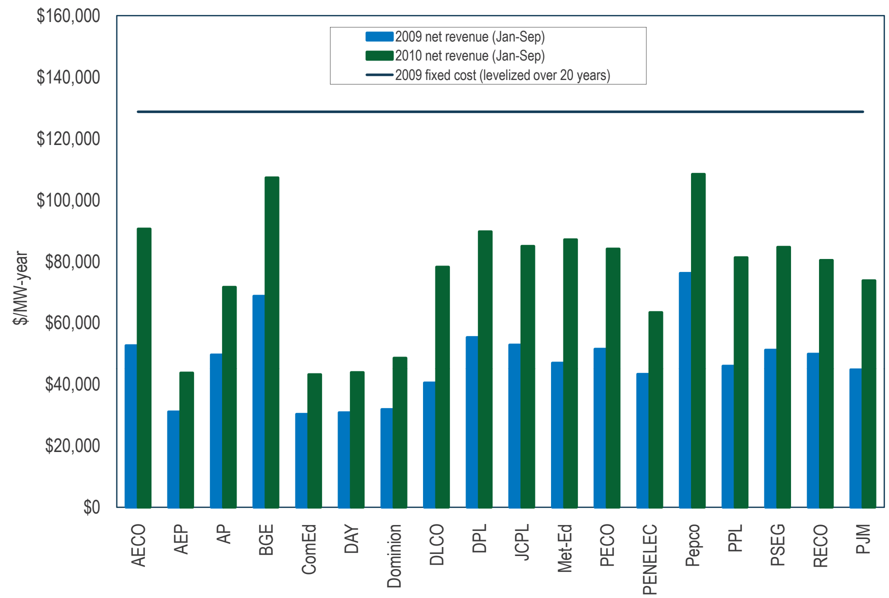


Table 3-20 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2009 and 2010 (See 2009 SOM, Table 3-23)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$52,670	$90,633	$128,705	41%	70%
AEP	$31,095	$43,752	$128,705	24%	34%
AP	$49,645	$71,647	$128,705	39%	56%
BGE	$68,755	$107,289	$128,705	53%	83%
ComEd	$30,340	$43,240	$128,705	24%	34%
DAY	$30,846	$43,935	$128,705	24%	34%
DLCO	$31,872	$48,579	$128,705	25%	38%
Dominion	$40,533	$78,203	$128,705	31%	61%
DPL	$55,297	$89,742	$128,705	43%	70%
JCPL	$52,852	$85,003	$128,705	41%	66%
Met-Ed	$46,992	$87,123	$128,705	37%	68%
PECO	$51,525	$84,129	$128,705	40%	65%
PENELEC	$43,339	$63,418	$128,705	34%	49%
Pepco	$76,206	$108,437	$128,705	59%	84%
PPL	$45,996	$81,295	$128,705	36%	63%
PSEG	$51,227	$84,695	$128,705	40%	66%
RECO	$49,926	$80,398	$128,705	39%	62%
PJM	$44,789	$73,781	$128,705	35%	57%

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



New Entrant Combined Cycle

Figure 3-3 New entrant CC zonal real-time 2010 net revenue by market for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (New Figure)

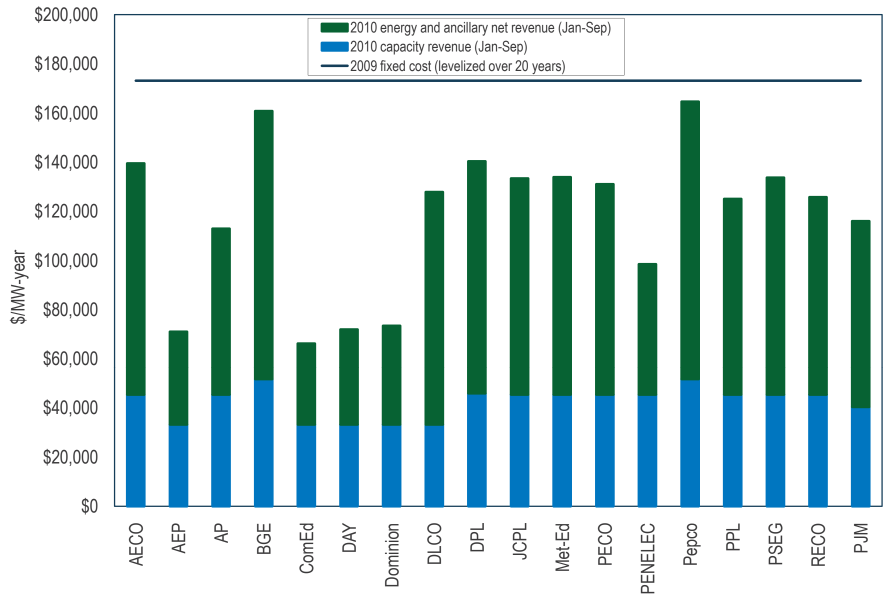
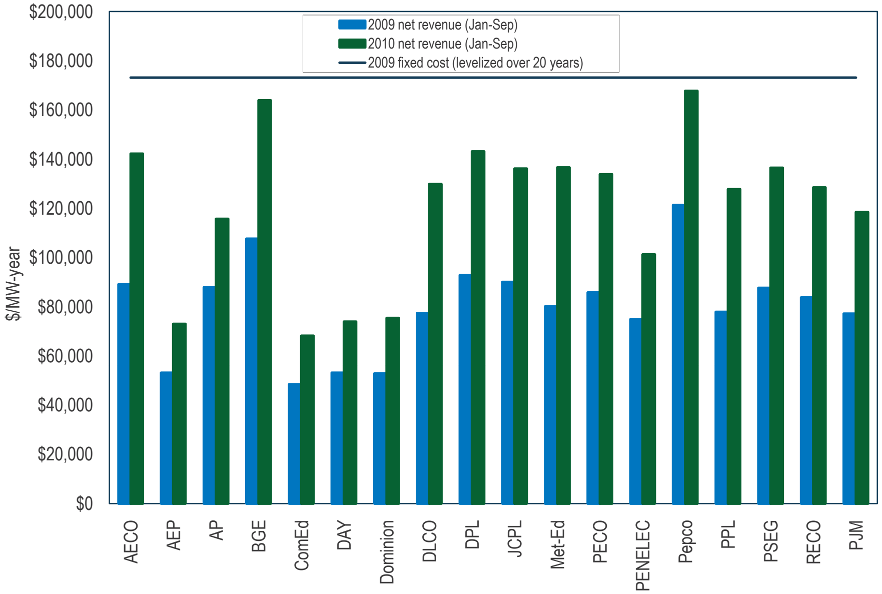


Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2009 and 2010 (See 2009 SOM, Table 3-25)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$89,124	$142,236	$173,174	51%	82%
AEP	$53,211	$73,050	$173,174	31%	42%
AP	$87,914	$115,720	$173,174	51%	67%
BGE	$107,673	$163,901	$173,174	62%	95%
ComEd	$48,506	$68,208	$173,174	28%	39%
DAY	$53,172	$73,964	$173,174	31%	43%
DLCO	$52,924	$75,436	$173,174	31%	44%
Dominion	$77,418	$129,869	$173,174	45%	75%
DPL	$92,884	$143,159	$173,174	54%	83%
JCPL	$90,126	$136,167	$173,174	52%	79%
Met-Ed	$80,163	$136,647	$173,174	46%	79%
PECO	$85,775	$133,822	$173,174	50%	77%
PENELEC	$74,950	$101,270	$173,174	43%	58%
Pepco	$121,317	$167,775	$173,174	70%	97%
PPL	$77,916	$127,793	$173,174	45%	74%
PSEG	$87,666	$136,496	$173,174	51%	79%
RECO	$83,802	$128,512	$173,174	48%	74%
PJM	$77,226	$118,487	$173,174	45%	68%

Figure 3-4 New entrant CC real-time 2009 and 2010 net revenue for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-5)



New Entrant Coal Plant

Figure 3-5 New entrant CP zonal real-time 2010 net revenue by market for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (New Figure)

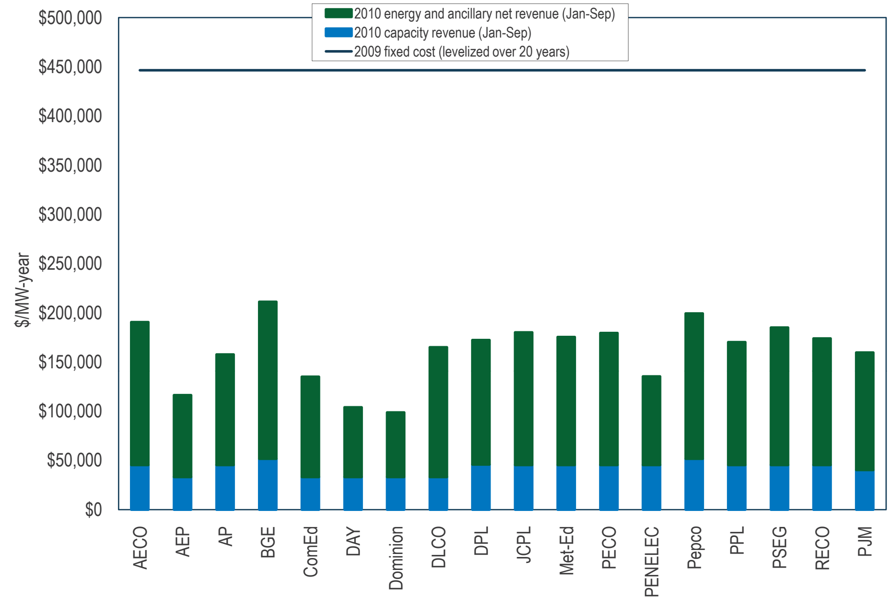
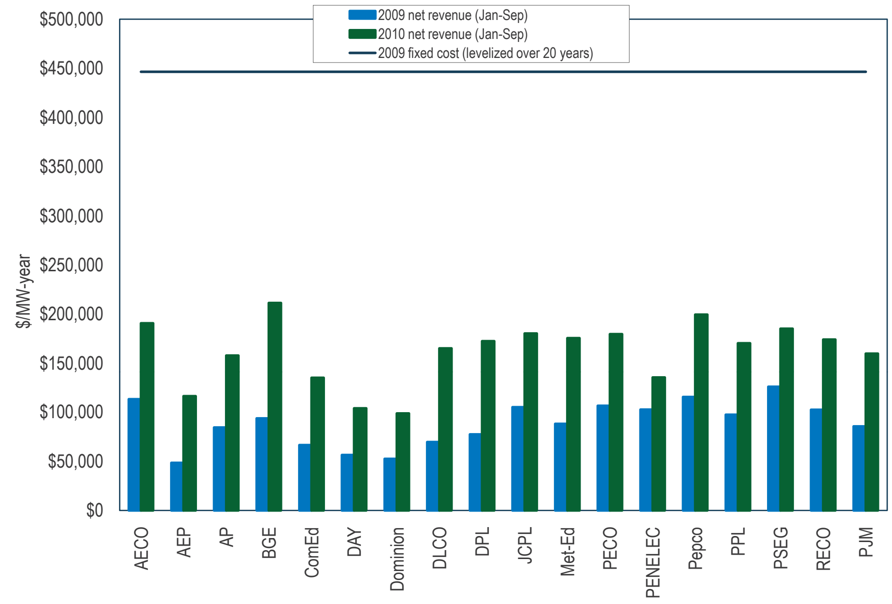


Table 3-22 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2009 and 2010 (See 2009 SOM, Table 3-27)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$113,359	$190,550	$446,550	25%	43%
AEP	$48,497	$116,363	$446,550	11%	26%
AP	$84,577	$157,748	$446,550	19%	35%
BGE	$93,822	$211,232	$446,550	21%	47%
ComEd	$66,675	$135,076	$446,550	15%	30%
DAY	$56,483	$104,022	$446,550	13%	23%
DLCO	$52,548	$98,900	$446,550	12%	22%
Dominion	$69,711	$165,122	$446,550	16%	37%
DPL	$77,436	$172,408	$446,550	17%	39%
JCPL	$105,112	$180,159	$446,550	24%	40%
Met-Ed	$88,210	$175,406	$446,550	20%	39%
PECO	$106,716	$179,597	$446,550	24%	40%
PENELEC	$102,672	$135,434	$446,550	23%	30%
Pepco	$115,660	$199,420	$446,550	26%	45%
PPL	$97,567	$170,273	$446,550	22%	38%
PSEG	$126,080	$185,101	$446,550	28%	41%
RECO	$102,517	$174,045	$446,550	23%	39%
PJM	$85,668	$159,611	$446,550	19%	36%

Figure 3-6 New entrant CP real-time 2009 and 2010 net revenue for January through September 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 September 30, 2010 (See 2009 SOM, Table 3-35)

	1-Jan-10		31-May-10		1-Jun-10		30-Sep-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%	68,347.0	41.0%
Gas	49,238.8	29.3%	48,991.4	29.3%	48,424.5	29.0%	47,924.2	28.7%
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%	30,604.0	18.4%
Oil	10,700.1	6.4%	10,649.4	6.4%	10,645.5	6.4%	10,741.6	6.4%
Solid waste	672.1	0.4%	672.1	0.4%	672.1	0.4%	680.1	0.4%
Wind	326.9	0.2%	409.5	0.2%	481.1	0.3%	511.7	0.3%
Total	167,853.8	100.0%	167,400.7	100.0%	166,756.8	100.0%	166,732.1	100.0%

Energy Production by Fuel Source

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

	GWh	Percent
Coal	279,394.7	49.9%
Nuclear	192,379.3	34.3%
Gas	64,024.4	11.4%
Natural Gas	62,810.2	11.2%
Landfill Gas	1,213.9	0.2%
Biomass Gas	0.4	0.0%
Hydroelectric	11,192.6	2.0%
Wind	5,599.2	1.0%
Waste	4,684.4	0.8%
Solid Waste	3,563.2	0.6%
Miscellaneous	1,121.2	0.2%
Oil	2,942.6	0.5%
Heavy Oil	2,506.1	0.4%
Light Oil	395.8	0.1%
Diesel	28.0	0.0%
Kerosene	12.7	0.0%
Jet Oil	0.1	0.0%
Solar	3.7	0.0%
Battery	0.3	0.0%
Total	560,221.2	100.0%

3 Hydroelectric generation does not net out the MWh used at pumped storage facilities to pump water.

Planned Generation Additions

Table 3-25 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through September 2010[4] (See 2009 SOM, Table 3-37)

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	1,169

PJM Generation Queues

Table 3-26 Queue comparison (MW): September 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	14,067	(8,667)	(62%)
2011	15,873	17,235	1,362	8%
2012	11,053	12,599	1,545	12%
2013	6,350	8,664	2,314	27%
2014	13,439	13,437	(2)	(0%)
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	75,144	(1,581)	(2%)

4 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 September 30, 2010[5, 6] (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	173	6,713	10,407
O Expired 31-Jul-05	1,978	1,348	144	4,104	7,574
P Expired 31-Jan-06	853	1,008	1,922	4,918	8,701
Q Expired 31-Jul-06	1,772	707	3,685	8,450	14,614
R Expired 31-Jan-07	5,511	648	708	15,974	22,840
S Expired 31-Jul-07	7,009	1,430	1,277	11,178	20,893
T Expired 31-Jan-08	12,636	397	299	14,235	27,566
U Expired 31-Jan-09	9,679	121	853	20,781	31,434
V Expired 31-Jan-10	13,330	55	104	3,218	16,707
W Expires 31-Jan-11	10,970	0	15	3	10,987
Total	65,134	24,979	10,010	199,885	300,008

5 The *2010 Quarterly State of the Market Report for PJM: January through September* contains all projects in the queue including reratings of existing generating units and energy only resources.
6 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

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

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	824	638	0	4,420
In-Service	740	621	0	3,287
Suspended	2,193	737	890	3,622
Under Construction	1,152	893	0	4,370
Withdrawn	519	522	0	3,186

Distribution of Units in the Queues

Table 3-29 Capacity additions in active or under-construction queues by control zone (MW): At September 30, 2010[7] (See 2009 SOM, Table 3-41)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
AECO	0	10	703	2	0	0	1,091	665	1,066	63	3,599
AEP	0	1,855	594	6	170	84	56	2,206	12,201	12	17,184
AP	32	958	2	13	108	0	428	724	1,388	0	3,653
BGE	0	0	0	30	0	1,640	0	132	0	0	1,802
ComEd	20	1,680	1,038	78	0	750	0	1,366	20,303	0	25,235
DAY	0	0	10	2	112	0	40	12	1,740	0	1,916
DLCO	0	0	0	0	0	91	0	0	0	0	91
Dominion	0	2,691	1,893	13	30	1,839	150	481	770	53	7,919
DPL	0	0	109	0	0	0	180	43	450	0	782
JCPL	0	1,080	27	33	0	0	465	0	0	0	1,605
Met-Ed	20	650	9	31	0	24	85	10	0	0	829
PECO	0	1,213	37	5	0	510	21	18	0	0	1,805
PENELEC	0	0	65	15	32	0	38	90	1,049	5	1,294
Pepco	0	2,025	230	0	0	0	0	0	0	0	2,255
PPL	20	0	139	10	143	1,600	104	33	179	0	2,228
PSEG	0	1,940	767	10	0	0	186	45	0	0	2,948
Total	92	14,101	5,622	248	594	6,538	2,844	5,824	39,147	133	75,144

7 In this section, unit type “Unknown” is referred to for units that the RTEP has not yet identified.

Table 3-30 Capacity additions in active or under-construction queues by LDA (MW): At September 30, 2010[8] (See 2009 SOM, Table 3-42)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	0	4,243	1,643	51	0	510	1,943	771	1,516	63	10,739
SWMAAC	0	2,025	230	30	0	1,640	0	132	0	0	4,057
WMAAC	40	650	213	56	175	1,624	228	133	1,228	5	4,350
RTO	52	7,184	3,537	111	420	2,764	674	4,789	36,402	66	55,998
Total	92	14,101	5,622	248	594	6,538	2,844	5,824	39,147	133	75,144

Table 3-31 Existing PJM capacity: At September 30, 2010[9] (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	1,264	0	8	1,902
AEP	0	4,355	3,668	57	1,005	2,106	21,568	0	955	33,713
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	1,903	28,403
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	164	3,558	3,494	8,617	0	0	22,859
DPL	0	376	2,496	96	0	0	1,919	0	0	4,887
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	39	505	0	6,834	0	497	8,161
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	2,866	0	5	3,553	2,535	10	0	11,890
Total	1	21,542	31,932	714	7,820	31,753	89,264	16	4,194	187,236

8 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.
9 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 September 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	18,925	377	10	0	2,089	16	4,194	42,918
10 to 20	0	3,976	4,740	129	49	0	6,148	0	0	15,042
20 to 30	0	158	490	38	3,438	16,186	9,997	0	0	30,307
30 to 40	0	101	5,276	39	435	14,953	31,657	0	0	52,461
40 to 50	0	0	2,501	128	2,480	615	24,346	0	0	30,069
50 to 60	0	0	0	4	348	0	13,523	0	0	13,875
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	31,932	714	7,820	31,753	89,264	16	4,194	187,236

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[10] (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%	4,243	11,284	28.7%
	Combustion Turbine	955	12.3%	8,230	24.0%	1,643	8,917	22.7%
	Diesel	49	0.6%	150	0.4%	51	151	0.4%
	Hydroelectric	2,042	26.2%	2,047	6.0%	0	2,047	5.2%
	Nuclear	615	7.9%	8,676	25.3%	510	8,572	21.8%
	Solar	0	0.0%	13	0.0%	1,943	1,956	5.0%
	Steam	4,135	53.0%	8,164	23.8%	771	4,800	12.2%
	Wind	0	0.0%	8	0.0%	1,516	1,524	3.9%
	Unknown	0	0.0%	0	0.0%	63	63	3.0%
	EMAAC Total	7,796	100.0%	34,330	100.0%	10,739	39,315	100.0%
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%	30	49	0.4%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	27.6%

10 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.

(cont'd) Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
	Steam	3,267	85.8%	7,732	65.2%	132	4,597	38.0%
	SWMAAC Total	3,807	100.0%	11,859	100.0%	4,057	12,109	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	40	40	0.2%
	Combined Cycle	0	0.0%	2,956	12.6%	650	3,606	16.9%
	Combustion Turbine	296	4.3%	2,054	8.8%	213	1,971	9.2%
	Diesel	35	0.5%	125	0.5%	56	145	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	22.5%
	Solar	0	0.0%	0	0.0%	228	228	1.1%
	Steam	6,042	88.6%	13,256	56.7%	133	7,346	34.5%
	Wind	0	0.0%	713	3.1%	1,228	1,942	9.1%
	Unknown	0	0.0%	0	0.0%	5	5	0.0%
	WMAAC Total	6,817	100.0%	23,379	100.0%	4,350	21,316	100.0%
RTO	Battery	0	0.0%	0	0.0%	52	52	0.0%
	Combined Cycle	0	0.0%	11,545	9.8%	7,184	18,729	12.9%
	Combustion Turbine	709	2.5%	19,244	16.4%	3,537	22,073	15.2%
	Diesel	48	0.2%	421	0.4%	111	484	0.3%
	Hydroelectric	1,401	5.0%	4,677	4.0%	420	3,696	2.5%
	Nuclear	0	0.0%	18,192	15.5%	2,764	20,956	14.4%
	Solar	0	0.0%	3	0.0%	674	676	0.5%
	Steam	25,931	92.3%	60,112	51.1%	4,789	38,969	26.8%
	Wind	0	0.0%	3,473	3.0%	36,402	39,876	27.4%
	Unknown	0	0.0%	0	0.0%	66	66	0.0%
	RTO Total	28,089	100.0%	117,667	100.0%	55,998	145,576	100.0%
All Areas	Total	46,509		187,236		75,144	218,317	

Characteristics of Wind Units

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

Type of Resource	Capacity Factor	Total Hours	Installed Capacity
Energy-Only Resource	19.4%	96,538	1,604
Capacity Resource	27.2%	189,394	2,590
All Units	25.2%	285,932	4,194

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

	Average MW Offered Daily	Intervals Marginal	Percent of All Intervals
At Negative Price	465.8	1,114	1.42%
All Wind	1,291.6	1,408	1.79%

Figure 3-7 Average hourly real-time generation of wind units in PJM, January through September 2010 (See 2009 SOM, Figure 3-11)

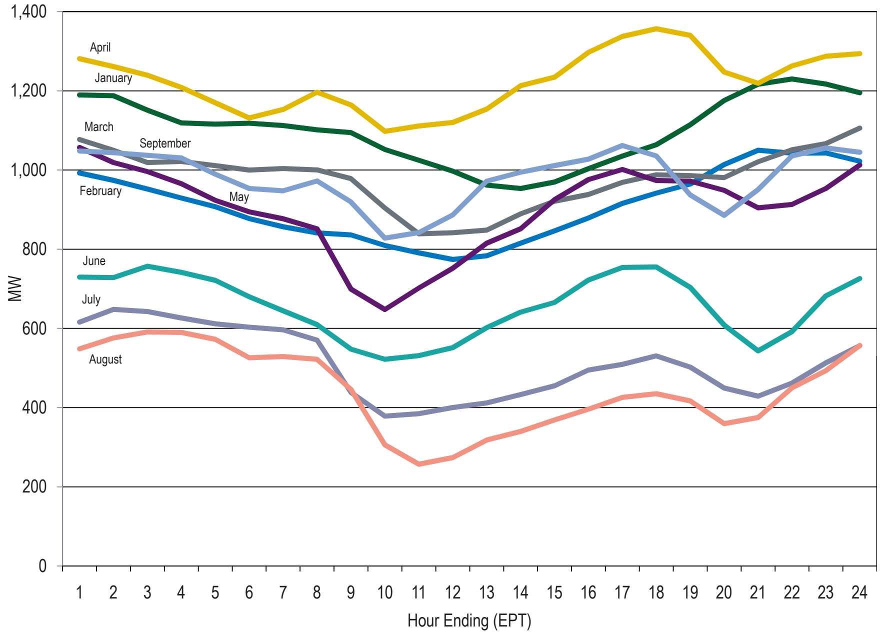


Figure 3-8 Average hourly day-ahead generation of wind units in PJM, January through September 2010 (See 2009 SOM, Figure 3-12)

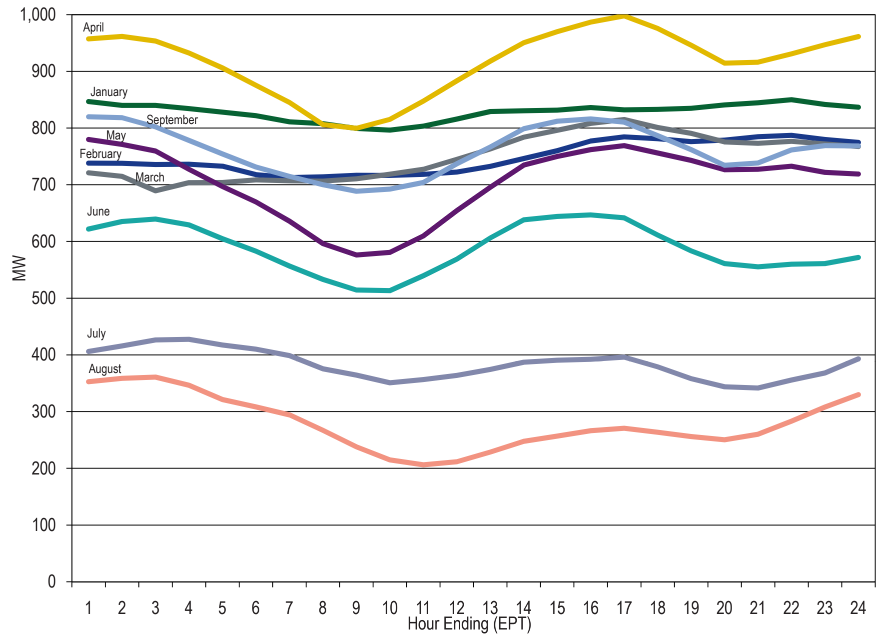


Table 3-36 Capacity factor of wind units in PJM by month, January through September 2010[11] (See 2009 SOM, Table 3-48)

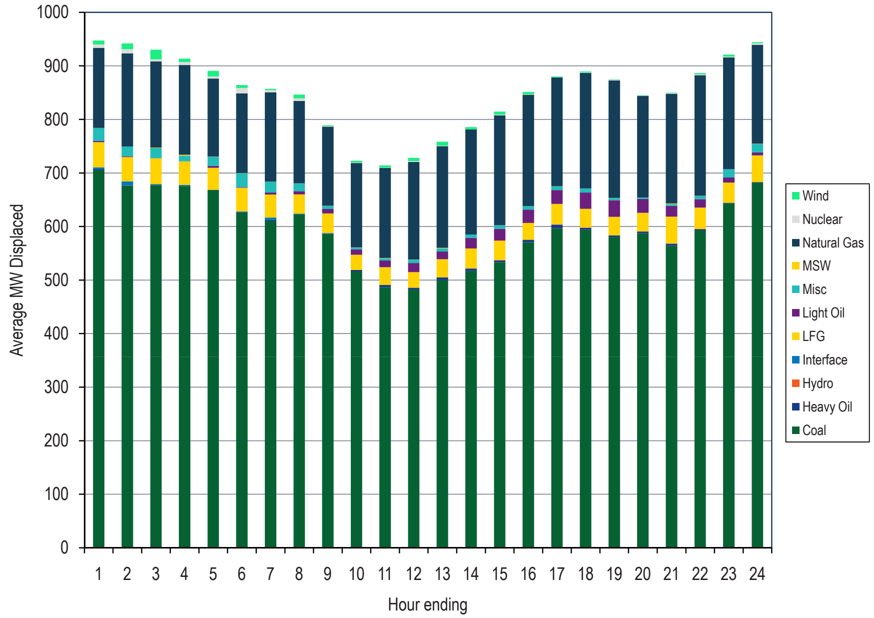
Month	Generation (MWh)	Capacity Factor
January	818,423.9	37.6%
February	612,044.4	29.3%
March	727,819.1	30.2%
April	881,317.4	36.3%
May	670,571.5	26.8%
June	472,775.6	19.0%
July	380,114.8	14.7%
August	330,818.7	12.4%
September	705,289.0	24.4%
October		
November		
December		
Annual	5,599,174.4	25.2%

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

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

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	31.0%	35.3%	18.2%		24.0%
	Average Wind Generation	960.6	1,188.6	650.8		814.9
	Average Load	86,485.1	73,871.4	74,018.2		89,846.1
Off-Peak	Capacity Factor	33.5%	37.3%	20.6%		26.2%
	Average Wind Generation	1,033.9	1,257.9	736.7		889.5
	Average Load	75,824.0	59,326.6	95,159.1		73,066.0

Figure 3-9 Marginal fuel at time of wind generation in PJM, January through September 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 Day-ahead load Day-ahead sales Day-ahead export transactions	Demand (Withdrawal) (RTO, East, West)	Real-time load Real-time sales Real-time export transactions
Day-ahead increment offers Day-ahead purchases Day-ahead import transactions	Supply (Injection) (RTO, East, West)	Real-time purchases Real-time 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 September 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	$40,472,496	$50,803,869
Feb	$7,434,068	$839,679	$16,548,988	$24,822,735	$11,425,494	$14,715	$22,346,529	$33,786,738
Mar	$9,549,963	$108,664	$26,025,562	$35,684,189	$8,836,886	$122,817	$16,823,288	$25,782,991
Apr	$6,998,364	$19,929	$13,251,273	$20,269,566	$7,633,141	$93,253	$22,870,495	$30,596,889
May	$6,024,108	$5,543	$15,490,257	$21,519,908	$5,127,307	$131,600	$38,987,045	$44,245,952
Jun	$6,722,329	$0	$19,339,846	$26,062,175	$3,511,264	$33,923	$56,903,524	$60,448,710
Jul	$8,210,636	$38,643	$17,728,976	$25,978,255	$4,601,788	$88,136	$62,814,415	$67,504,339
Aug	$7,697,174	$1	$21,164,586	$28,861,761	$3,622,670	$66,535	$41,526,188	$45,215,393
Sep	$6,057,598	$13,611	$13,471,368	$19,542,577	$8,433,892	$27,971	$40,031,736	$48,493,599
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	$63,473,794	$628,972	$342,775,715	$406,878,481
Share of Annual Charges	29.1%	0.8%	70.1%	100.0%	15.6%	0.2%	84.2%	100.0%

Table 3-42 Regional balancing charges allocation: January through September 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	$24,175,834 10.7%	$963,847 0.4%	$25,139,682 11.1%	$63,249,775 28.0%	$31,110,560 13.8%	$18,839,412 8.3%	$113,199,747 50.2%	$138,339,428 61.3%
East	$42,654,235 18.9%	$1,589,085 0.7%	$44,243,320 19.6%	$11,685,727 5.2%	$5,263,247 2.3%	$2,754,031 1.2%	$19,703,005 8.7%	$63,946,325 28.3%
West	$12,636,155 5.6%	$516,075 0.2%	$13,152,230 5.8%	$5,690,585 2.5%	$2,385,359 1.1%	$2,142,870 0.9%	$10,218,813 4.5%	$23,371,043 10.4%
Total	$79,466,225 35.2%	$3,069,008 1.4%	$82,535,232 36.6%	$80,626,087 35.7%	$38,759,166 17.2%	$23,736,312 10.5%	$143,121,565 63.4%	$225,656,797 100%

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.

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.

Deviations

Allocation

Table 3-43 Monthly balancing operating reserve deviations (MWh): Calendar year 2009 and January through September 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	2,269,735	15,509,950
Apr	6,873,427	3,836,896	2,275,153	12,985,477	7,006,983	4,668,407	2,146,855	13,822,245
May	6,958,699	5,184,983	2,382,351	14,526,033	9,004,034	4,228,004	2,429,552	15,661,590
Jun	8,569,879	4,603,052	2,635,991	15,808,922	10,936,989	3,964,478	3,200,282	18,101,749
Jul	9,233,511	5,129,409	2,243,337	16,606,257	10,928,408	3,847,011	3,452,080	18,227,500
Aug	9,961,944	5,425,344	2,427,539	17,814,827	9,747,045	3,417,328	3,203,587	16,367,960
Sep	7,972,378	4,171,876	2,109,506	14,253,759	9,480,237	3,587,356	2,543,115	15,610,709
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	82,320,769	39,891,049	24,416,764	146,628,582
Share of Annual Deviations	52.9%	31.1%	16.0%	100.0%	56.1%	27.2%	16.7%	100.0%

Table 3-44 Regional charges determinants (MWh): January through September 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	531,074,577	21,317,226	552,391,803	82,320,769	39,891,049	24,416,764	146,628,582	699,020,385
East	292,229,113	11,518,295	303,747,408	52,077,789	26,670,526	12,734,372	91,482,687	395,230,095
West	238,845,464	9,798,931	248,644,395	30,007,962	13,154,912	11,677,454	54,840,328	303,484,723

Balancing Operating Reserve Charge Rate

Figure 3-10 Daily RTO reliability and deviation rates ($/MWh): January through September 2010 (See 2009 SOM, Figure 3-14)

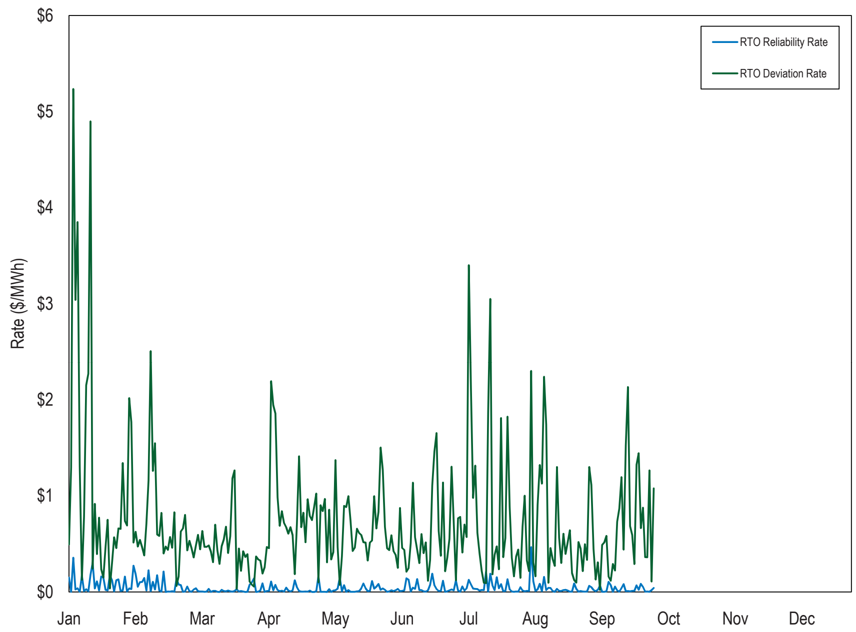


Figure 3-11 Daily regional reliability and deviation rates ($/MWh): January through September 2010 (See 2009 SOM, Figure 3-15)

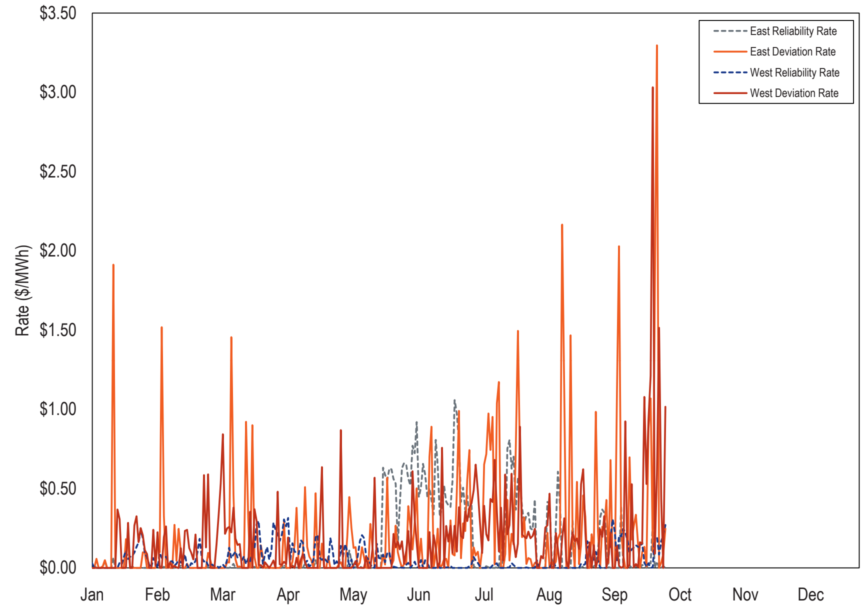


Table 3-45 Regional balancing operating reserve rates ($/MWh): January through September 2010 (See 2009 SOM, Table 3-58)

	Reliability ($/MWh)	Deviations ($/MWh)
RTO	0.044	0.741
East	0.132	0.211
West	0.060	0.179

Operating Reserve Credits by Category

Figure 3-12 Operating reserve credits: January through September 2010 (See 2009 SOM, Figure 3-16)

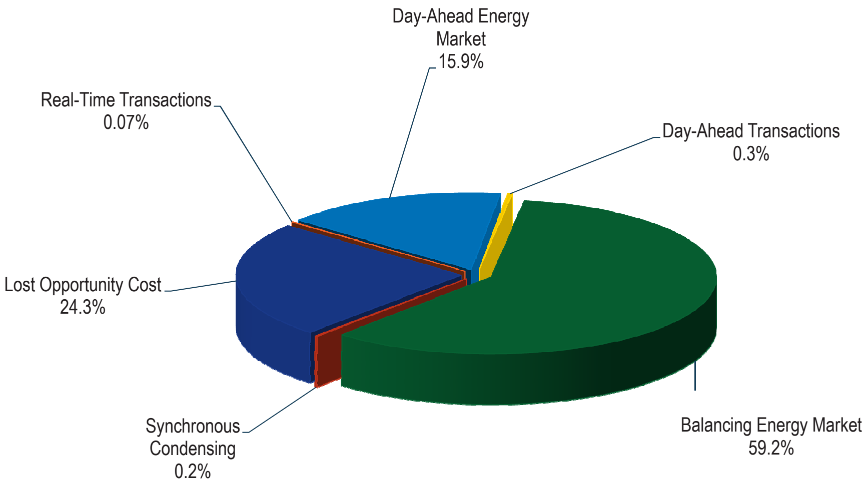


Table 3-46 Credits by month (By operating reserve market): January through September 2010 (See 2009 SOM, Table 3-59)[14]

	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	$3,333,858	$47,812,040
Feb	$11,382,585	$42,910	$14,715	$17,778,182	$77,139	$1,712,235	$31,007,765
Mar	$8,831,771	$5,115	$122,817	$13,931,307	$15,603	$1,971,841	$24,878,454
Apr	$7,633,141	$0	$93,253	$17,089,233	$0	$4,531,810	$29,347,437
May	$5,117,845	$9,462	$131,600	$23,182,507	$1,236	$15,665,943	$44,108,593
Jun	$3,469,143	$42,121	$33,923	$38,730,332	$196,537	$15,681,736	$58,153,793
Jul	$3,974,505	$627,284	$88,136	$36,589,423	$0	$23,571,309	$64,850,657
Aug	$3,391,194	$231,476	$66,535	$23,966,310	$0	$15,010,705	$42,666,220
Sep	$8,248,826	$185,065	$27,971	$25,726,609	$0	$13,630,437	$47,818,909
Oct							
Nov							
Dec							
Total	$62,248,544	$1,225,250	$628,972	$231,140,712	$290,515	$95,109,875	$390,643,869
Share of Credits	15.9%	0.3%	0.2%	59.2%	0.1%	24.3%	100.0%

Characteristics of Credits and Charges

Types of Units

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

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	34.5%	0.0%	58.0%	7.4%	$86,036,382
Combustion Turbine	1.6%	0.5%	50.2%	47.8%	$132,420,673
Diesel	3.7%	0.0%	75.7%	20.7%	$514,429
Hydro	0.0%	0.0%	100.0%	0.0%	$371,295
Landfill	0.0%	0.0%	0.0%	100.0%	$13,784,394
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	19.6%	0.0%	73.0%	7.4%	$155,760,941
Wind Farm	0.0%	0.0%	100.0%	0.0%	$233,059

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

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

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	47.7%	0.0%	21.6%	6.7%
Combustion Turbine	3.3%	100.0%	28.8%	66.5%
Diesel	0.0%	0.0%	0.2%	0.1%
Hydro	0.0%	0.0%	0.2%	0.0%
Landfill	0.0%	0.0%	0.0%	14.5%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	49.0%	0.0%	49.2%	12.2%
Wind Farm	0.0%	0.0%	0.1%	0.0%
Total	$62,248,544	$628,972	$231,133,780	$95,109,875

Geography of Balancing Credits and Charges

Table 3-49 Monthly balancing operating reserve charges and credits to generators (By location): January through September 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	$249,304	$2,162,794	$29,069,084	$2,730,988	$31,800,072	$1,971,007	$263,791	$2,234,797	$5,077,725	$602,870	$5,680,596	8.6%	78.4%
Feb	$1,069,496	$138,378	$1,207,873	$14,194,451	$1,375,982	$15,570,433	$998,751	$132,679	$1,131,430	$3,583,730	$336,253	$3,919,983	6.9%	62.9%
Mar	$591,204	$125,590	$716,795	$8,223,758	$1,399,277	$9,623,035	$756,085	$166,509	$922,594	$5,707,549	$572,564	$6,280,114	6.4%	63.9%
Apr	$904,242	$342,520	$1,246,763	$12,334,741	$3,370,088	$15,704,830	$1,099,662	$393,474	$1,493,136	$4,754,491	$1,161,722	$5,916,213	9.0%	73.7%
May	$919,969	$1,219,952	$2,139,922	$17,646,849	$13,869,787	$31,516,636	$935,038	$1,196,289	$2,131,327	$5,535,658	$1,796,157	$7,331,815	9.7%	88.1%
Jun	$1,334,394	$1,453,614	$2,788,008	$33,621,482	$14,552,023	$48,173,505	$1,243,549	$1,370,749	$2,614,298	$5,108,850	$1,129,713	$6,238,563	8.9%	93.6%
Jul	$2,253,574	$2,323,169	$4,576,743	$29,626,646	$19,048,045	$48,674,691	$1,898,910	$2,015,996	$3,914,905	$6,962,777	$4,523,264	$11,486,041	12.5%	92.8%
Aug	$1,575,552	$1,449,229	$3,024,781	$18,625,295	$10,495,220	$29,120,516	$1,480,028	$1,643,754	$3,123,782	$5,341,015	$4,515,485	$9,856,499	13.5%	91.4%
Sep	$1,202,073	$952,764	$2,154,837	$16,755,277	$12,557,752	$29,313,029	$1,587,360	$1,200,168	$2,787,528	$8,971,332	$1,072,685	$10,044,017	10.2%	82.3%
Oct														
Nov														
Dec														
Average	49.6%	49.6%	49.6%	77.9%	83.5%	79.5%	50.4%	50.4%	50.4%	22.1%	16.5%	20.5%	9.5%	80.8%

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 September 2010 (See 2009 SOM, Table 3-66)[15]

	Reliability Credits	Deviation Credits	Total Credits
RTO	$25,054,465	$112,894,940	$137,949,404
East	$44,243,320	$19,696,897	$63,940,218
West	$13,152,230	$10,140,624	$23,292,854
Total	$82,450,015	$142,732,461	$225,182,476

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

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	82,321,091	39,891,049	24,437,806	146,649,946

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

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	82,321,091	39,891,049	24,437,806	146,649,946
Balancing Rate ($/MWh)	1.536	1.536	1.536	1.536
Charges ($)	$126,404,867	$61,253,109	$37,524,499	$225,182,476

Table 3-53 Actual regional credits, charges, rates and charge allocation (MWh): January through September 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	$25,054,465	552,391,803	0.045	$25,054,465	$112,894,940	146,649,946	0.770	$112,894,940	$137,949,404
East	$44,243,320	303,747,408	0.146	$44,243,320	$19,696,897	91,501,468	0.215	$19,696,897	$63,940,218
West	$13,152,230	248,644,395	0.053	$13,152,230	$10,140,624	54,842,911	0.185	$10,140,624	$23,292,854
Total	$82,450,015	552,391,803	NA	$82,450,015	$142,732,461	146,649,946	NA	$142,732,461	$225,182,476

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

Table 3-54 Difference in total charges between old rules and new rules: January through September 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	$126,404,867	$61,253,109	$37,524,499	$225,182,476
Charges (Current)	$79,383,516	$3,066,499	$82,450,015	$80,384,439	$38,662,409	$23,685,613	$142,732,461
Difference	$79,383,516	$3,066,499	$82,450,015	($46,020,429)	($22,590,700)	($13,838,886)	($82,450,015)

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 September 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
Jul	8,389,094	12,813,573	1,840,017	3,503,722
Aug	7,862,123	11,648,289	1,465,333	2,676,900
Sep	8,188,967	11,532,284	2,103,152	3,105,498
Total	73,267,095	106,310,830	18,715,203	27,129,138

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

Month	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,708,013	$10,190,867	($2,517,146)
Feb	$5,382,344	$3,936,420	($1,445,924)
Mar	$4,612,939	$3,468,829	($1,144,110)
Apr	$6,530,621	$5,301,308	($1,229,313)
May	$13,792,538	$10,102,237	($3,690,302)
Jun	$18,748,323	$10,628,729	($8,119,594)
Jul	$18,164,125	$14,194,310	($3,969,815)
Aug	$9,792,633	$7,531,136	($2,261,497)
Sep	$12,912,392	$10,600,518	($2,311,874)
Total	$102,643,927	$75,954,353	($26,689,574)

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

Region	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Adjusted Virtual Deviations (MWh)	Balancing Rate Under Old Rules ($/MWh)	Balancing Rate Under Current Rules ($/MWh)	Charges Under Old Rules	Charges Under Current Rules	Differerence
RTO	18,715,203	27,129,138	45,844,342	2.16	1.40	$102,643,926	$66,619,974	($36,023,952)
East	12,277,110	16,595,492	28,872,602	0.00	0.18	$0	$6,310,630	$6,310,630
West	6,372,482	10,298,629	16,671,111	0.00	0.00	$0	$3,023,749	$3,023,749

Segmented Make Whole Payments

Table 3-58 Impact of segmented make whole payments: December 2008 through October 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	$13,458,120	$13,672,172	$214,052
2010	Apr	$16,441,644	$17,036,058	$594,414
2010	May	$21,854,306	$23,455,721	$1,601,415
2010	Jun	$36,297,521	$38,885,349	$2,587,828
2010	Jul	$32,247,658	$37,049,632	$4,801,974
2010	Aug	$21,851,376	$24,333,948	$2,482,572
2010	Sep	$24,286,200	$25,683,305	$1,397,105
Total		$416,042,294	$439,126,259	$23,083,966

Table 3-59 Impact of segmented make whole payments (By unit type): January through September 2010 (See 2009 SOM, Table 3-75)[16]

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	7273	$6,198	$6,868	$670	$45,077,122	$49,950,143	$4,873,021
Large Frame Combustion Turbine (135 - 180 MW)	3215	$6,125	$7,049	$924	$19,691,696	$22,662,336	$2,970,640
Medium Frame Combustion Turbine (30 - 65 MW)	8181	$2,842	$3,204	$362	$23,246,625	$26,210,577	$2,963,951
Petroleum/Gas Steam (Pre-1985)	1020	$64,134	$65,436	$1,303	$65,416,233	$66,744,917	$1,328,684
Medium-Large Frame Combustion Turbine (65 - 125 MW)	2490	$4,864	$5,341	$477	$12,112,441	$13,299,362	$1,186,921
Petroleum/Gas Steam (Post-1985)	1877	$2,041	$2,370	$329	$3,830,891	$4,448,249	$617,358
Sub-Critical Coal	23922	$1,421	$1,445	$24	$34,002,003	$34,573,565	$571,562
Small Frame Combustion Turbine (0 - 29 MW)	3067	$1,633	$1,743	$110	$5,007,478	$5,344,633	$337,155
Diesel	3432	$96	$114	$18	$330,443	$390,511	$60,068
Super-Critical Coal	7204	$1,093	$1,093	$0	$7,874,597	$7,874,796	$199
Nuclear	1006	$0	$0	$0	$0	$0	$0
Hydro	576	$262	$262	$0	$150,717	$150,717	$0

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

Unit Type	Share of Increase
Combustion Turbines	50.0%
Combined-Cycle	32.7%
Steam	16.9%
Diesel	0.4%

16 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 3-59.

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 September 2010 (See 2009 SOM, Table 3-78)

Unit Type	Number of Units	Observations
Combined-Cycle	3	8
Large Frame Combustion Turbine (135 - 180 MW)	6	81
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	113
Petroleum/Gas Steam (Pre-1985)	5	12
Sub-Critical Coal	25	250
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 September 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	$480,014	$3,971	$1,929,145	$3,524,005	$5,937,135	1.5%
AEP	$2,263,256	$13,296	$27,048,789	$2,825,550	$32,150,892	8.3%
AP	$1,452,413	$0	$4,118,792	$6,564,651	$12,135,856	3.1%
BGE	$4,395,983	$0	$8,633,699	$511,135	$13,540,817	3.5%
ComEd	$1,295,180	$4,080	$8,130,739	$5,885,245	$15,315,244	3.9%
DAY	$203,534	$0	$1,985,475	$290,918	$2,479,927	0.6%
DLCO	$2,349,144	$0	$9,902,666	$144,349	$12,396,159	3.2%
Dominion	$4,228,691	$0	$24,005,538	$50,802,524	$79,036,753	20.3%
DPL	$2,596,665	$10,337	$6,960,197	$1,502,119	$11,069,319	2.8%
JCPL	$2,307,738	$0	$5,394,610	$858,547	$8,560,894	2.2%
Met-Ed	$292,312	$0	$2,055,817	$562,727	$2,910,855	0.7%
PECO	$1,840,315	$2,095	$5,412,001	$2,356,875	$9,611,287	2.5%
PENELEC	$165,418	$27,409	$1,141,900	$2,334,790	$3,669,518	0.9%
Pepco	$3,898,184	$0	$65,271,187	$12,140,136	$81,309,507	20.9%
PPL	$133,000	$0	$5,234,632	$1,991,069	$7,358,702	1.9%
PSEG	$34,346,696	$567,782	$53,915,527	$2,815,234	$91,645,239	23.6%
RECO	$0	$0	$0	$0	$0	0.0%
External	$0	$0	$0	$0	$0	0.0%
Total	$62,248,544	$628,972	$231,140,712	$95,109,875	$389,128,103	100.0%

Table 3-64 Top 10 units and organizations receiving total operating reserve credits: January through September 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	$29,445,765	7.6%	7.6%	$90,735,278	23.3%	23.3%
2	$21,957,259	5.6%	13.2%	$73,690,019	18.9%	42.3%
3	$21,272,780	5.5%	18.7%	$54,900,544	14.1%	56.4%
4	$18,256,867	4.7%	23.4%	$25,177,668	6.5%	62.8%
5	$14,092,829	3.6%	27.0%	$17,374,058	4.5%	67.3%
6	$12,524,539	3.2%	30.2%	$17,163,809	4.4%	71.7%
7	$10,284,726	2.6%	32.9%	$15,258,698	3.9%	75.6%
8	$4,868,869	1.3%	34.1%	$14,337,000	3.7%	79.3%
9	$4,783,701	1.2%	35.3%	$10,046,413	2.6%	81.9%
10	$4,253,062	1.1%	36.4%	$6,006,489	1.5%	83.4%

Table 3-65 Top 10 units and organizations receiving day-ahead generator credits: January through September 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	$13,648,456	21.9%	21.9%	$34,271,260	55.1%	55.1%
2	$8,019,436	12.9%	34.8%	$4,616,829	7.4%	62.5%
3	$7,133,477	11.5%	46.3%	$4,475,372	7.2%	69.7%
4	$2,824,506	4.5%	50.8%	$2,666,266	4.3%	73.9%
5	$1,875,580	3.0%	53.8%	$2,066,275	3.3%	77.3%
6	$1,812,089	2.9%	56.7%	$2,049,253	3.3%	80.6%
7	$1,797,737	2.9%	59.6%	$1,875,580	3.0%	83.6%
8	$1,358,925	2.2%	61.8%	$1,770,586	2.8%	86.4%
9	$1,280,779	2.1%	63.9%	$1,136,211	1.8%	88.2%
10	$1,136,211	1.8%	65.7%	$1,066,890	1.7%	90.0%

Table 3-66 Top 10 units and organizations receiving synchronous condensing credits: January through September 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	$47,478	7.5%	7.5%	$567,782	90.3%	90.3%
2	$47,176	7.5%	15.0%	$27,409	4.4%	94.6%
3	$46,849	7.4%	22.5%	$14,309	2.3%	96.9%
4	$44,323	7.0%	29.5%	$13,296	2.1%	99.0%
5	$44,031	7.0%	36.5%	$4,080	0.6%	99.7%
6	$37,699	6.0%	42.5%	$2,095	0.3%	100.0%
7	$31,142	5.0%	47.5%			
8	$27,863	4.4%	51.9%			
9	$27,604	4.4%	56.3%			
10	$25,858	4.1%	60.4%			

Table 3-67 Top 10 units and organizations receiving balancing generator credits: January through September 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	$22,306,460	9.7%	9.7%	$53,082,632	23.0%	23.0%
2	$21,272,051	9.2%	18.9%	$50,312,355	21.8%	44.7%
3	$17,918,553	7.8%	26.6%	$31,859,970	13.8%	58.5%
4	$10,024,439	4.3%	30.9%	$21,840,941	9.4%	68.0%
5	$9,695,765	4.2%	35.1%	$13,691,304	5.9%	73.9%
6	$8,277,061	3.6%	38.7%	$12,736,753	5.5%	79.4%
7	$6,073,193	2.6%	41.3%	$11,242,727	4.9%	84.3%
8	$3,717,281	1.6%	43.0%	$3,378,186	1.5%	85.7%
9	$2,708,497	1.2%	44.1%	$3,105,615	1.3%	87.1%
10	$2,649,408	1.1%	45.3%	$2,493,475	1.1%	88.1%

Table 3-68 Top 10 units and organizations receiving lost opportunity cost credits: January through September 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	$4,528,271	4.8%	4.8%	$37,354,677	39.3%	39.3%
2	$4,415,166	4.6%	9.4%	$14,312,947	15.0%	54.3%
3	$3,584,978	3.8%	13.2%	$7,465,460	7.8%	62.2%
4	$2,923,880	3.1%	16.2%	$3,833,009	4.0%	66.2%
5	$2,633,988	2.8%	19.0%	$2,841,276	3.0%	69.2%
6	$2,558,140	2.7%	21.7%	$2,814,097	3.0%	72.1%
7	$2,325,374	2.4%	24.2%	$2,813,603	3.0%	75.1%
8	$2,055,519	2.2%	26.3%	$2,507,605	2.6%	77.7%
9	$2,050,391	2.2%	28.5%	$1,644,622	1.7%	79.5%
10	$1,995,456	2.1%	30.6%	$1,566,141	1.6%	81.1%

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 nine 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 -824 GWh.[1] Gross monthly import volumes averaged 3,475 GWh while gross monthly exports averaged 4,299 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market.** During the first nine months of 2010, PJM was a net exporter of energy in the Day-Ahead Market in all months except August. In the Day-Ahead Market, monthly net interchange averaged -740 GWh. Gross monthly import volumes averaged 7,075 GWh while gross monthly exports averaged 7,815 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** During the first nine months of 2010, gross imports in the Day-Ahead Energy Market were 204 percent of the Real-Time Market's gross imports (111 percent for the calendar year 2009), gross exports in the Day-Ahead Market were 182 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 90 percent of net interchange in the Real-Time Energy Market (-7,412 GWh in the Real-Time Market and -6,658 GWh in the Day-Ahead Market).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market, during the first nine months of 2010, there were net exports at 15 of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Market accounted for 70 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 30 percent, PJM/Neptune (NEPT) with 20 percent and PJM/MidAmerican Energy Company (MEC) with 20 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 55 percent of the total net PJM exports in the Real-Time Market. Five PJM interfaces had net imports, with two importing interfaces accounting for 87 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 75 percent and PJM/Michigan Electric Coordinated System (MECS) with 12 percent.[2]

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, during the first nine months of 2010, there were net exports at 12 of PJM's 21 interfaces. The top four net exporting interfaces accounted for 89 percent of the total net exports: PJM/western Alliant Energy Corporation (ALTW) with 33 percent, PJM/NYIS with 32 percent, PJM/NEPT with 14 percent and PJM/MidAmerican Energy Company (MEC) with 10 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 47 percent of the total net PJM exports in the Day-Ahead Market. Nine PJM interfaces had net imports in the Day-Ahead Market, with two interfaces accounting for 71 percent of the total net imports: PJM/OVEC with 40 percent and PJM/Michigan Electric Coordinated System (MECS) with 31 percent.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** During the first nine 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

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, one PJM interface had a net interchange of zero.

Midwest ISO. Over the first nine months of 2010, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $34.51 while the Midwest ISO LMP at the border was $34.88, a difference of $0.37. 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 nine 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 nine months of 2010, the PJM average hourly LMP at the PJM/NYISO border was $48.33 while the NYISO LMP at the border was $45.66, a difference of $2.67. While the average hourly flow reflected exports from PJM into the NYISO, further analysis of hourly interchange showed 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).**[3] 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 nine 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."[4] 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.*[5] 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.[6] The Commission requested that the parties provide additional evidence regarding the proposed solutions. On August 16, 2010, the NYISO provided their response to the July 15th Order.[7] On September 15, 2010, the Market Monitoring Unit (MMU) responded to the NYISO filing.[8] The MMU commented that the NYISO response lacked detail and focus in implementing solutions that could be implemented quickly, and continued to lack detailed and firm timelines for implementation. Additionally, the MMU questioned the curtailment priority granted to transactions scheduled on non-firm transmission when electing to purchase "buy-through of congestion" as well as the inability to implement a market to market congestion management agreement with PJM. Finally, the MMU provided comments and recommendations on implementing an interface pricing solution in the NYISO to mitigate the incentives to scheduling circuitous paths into and out of the NYISO. The Market Monitor actively participated in the meeting of the Broader Regional Markets Group in Philadelphia on September 27, 2010, and continues to advocate in that process a joint operating agreement between NYISO and PJM that is equivalent to or better than the JOA between the Midwest ISO and PJM.

- **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 nine months of 2010. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. The MMU believes that this

3 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed October 15, 2010, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (208 KB).

4 128 FERC ¶ 61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶ 61,239.

5 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (January 12, 2010) (Accessed October 15, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

6 132 FERC ¶ 61,031.

7 See NYISO. "*Response to Questions and Supplemental Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow*" Docket No. ER08-1281-004 (August 16, 2010) (Accessed October, 14, 2010). <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/08/NYISO_resp_To_FERC_questions_8_13_10.pdf> (135 KB).

8 See "Comments of the Independent Market Monitor for PJM."Docket No. ER08-1281-004 (September 15, 2010) (Accessed October 14, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Comments_ER08-1281-004_20100915.pdf> (203 KB).

approach should be the minimum 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.[9] 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.[10] On March 8, 2010, after the settlement discussions mediated by the Federal Energy Regulatory Commission (FERC) ended, the Midwest ISO filed complaints with FERC against PJM.[11] On April 12, 2010, PJM answered and filed a counter complaint.[12] These matters are now pending before the Commission in settlement proceedings.[13] 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."[14]

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[15] 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 nine months of 2010.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[16] 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 nine 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.[17] The MMU responded to the filing on February 23, 2010.[18] 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.[19] On May 28, 2010, the Commission conditionally approved the revised PJM/PEC JOA.[20] 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.[21] 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.[22] The MMU moved for a technical conference to explore these issues.[23] As of September 30, 2010, the Commission had not made any additional issuances related to the Compliance Filing or the comments submitted by the MMU.

9 See PJM. "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,294 KB).

10 See PJM. "PJM/MISO Market Flow Calculation Error"(September 10, 2009) (Accessed October 15, 2010) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

11 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).

12 Complaint of PJM Interconnection, L.L.C., filed in EL10-60-000 at 19.

13 131 FERC ¶ 61,284 (June 29, 2010).

14 See PJM. "PJM-MISO-MOU-May-2010" (May 27, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pjm-miso-mou-may-2010.ashx> (313 KB).

15 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

16 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (February 2, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (2,983 KB).

17 See PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).

18 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010) (Accessed October 15, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Motion_to_Intervene_and_Comments_ER10-713-000_20100225.pdf> (225 KB).

19 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.

20 See Docket No. ER10-713-000. Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Progress Energy Carolinas.

21 See PJM/PEC compliance filing in Docket No. ER10-713-002.

22 See IMM response to PJM/PEC compliance filing in Docket No. ER10-713-002.

23 *Id.*

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[24] 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 nine months of 2010, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[25] This 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 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 nine months of 2010, PSE&G's FTR credits were $335,809 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 nine months of 2010, Con Edison's congestion credits were less than the associated congestion charges by approximately $1.6 million.

  In effect, Con Edison has been given congestion credits that are equivalent to a special class of FTRs uniquely available to Con Edison covering positive congestion with subordinated rights to revenue. However, Con Edison, unlike standard FTR holders, is not treated as having an FTR when congestion is negative. A standard FTR holder in that position would pay the negative congestion credits, but Con Edison does not. During the first nine months of 2010, Con Edison's negative congestion credits would have been approximately $28,000.

Under the terms of its 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 five percent of the hours during the first nine months of 2010.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[26] By order issued September 16, 2010, the Commission approved this settlement,[27] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[28] The Commission explained (at PP 49–50):

> We find that the Settlement, the 2008 1000 MW TSAs and the JOA Protocol are a just and reasonable means of continuing service to ConEd and do not create undue harm to pricing in the NYISO or PJM. Both the parties supporting the Settlement and NRG generally agree that the 2008 1,000 MW TSAs are economic in roughly 88 percent of hours. Further, ConEd placed into evidence data that during the hours when prices are lower in NYISO than PJM, the price differential usually is not great, but, when prices in NYISO are higher than PJM, they are substantially higher. [Footnote omitted]

24 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

25 111 FERC ¶ 61,228 (2005).

26 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.

27 *PJM Interconnection, L.L.C., et al.*, 132 FERC ¶61,221.

28 *See, e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010). The MMU questioned whether allowing rollover is appropriate and raised concerns that continuing these agreements could interfere with the efficient management of the NYISO/PJM seam, accord preferential access to transmission service and limit security constrained least cost dispatch. The MMU questioned whether a valid offsetting reliability consideration had been identified and explained. The MMU noted, "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, that MMU argued,"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."

Moreover, the Commission has established other procedures to address the loop flow issue comprehensively. [fn.79: Pursuant to Commission orders in Docket No. ER08-1281, the scheduling and seams issues are being addressed. On January 12, 2010, NYISO submitted a status report on the progress of the development of (1) the buy-through congestion proposal; (2) the congestion management/market-to-market coordination proposal; (3) interface pricing revisions; and (4) enhanced interregional transaction coordination. On July 15, 2010, the Commission issued an order conditionally accepting the status report and directing the parties to provide additional information on the proposed comprehensive solutions. New York Indep. Sys. Operator, Inc., 132 FERC ¶ 61,031 (2010).] As ConEd notes, neither the 2008 1,000 MW TSAs nor the JOA Protocol would prevent PJM and NYISO from modifying their scheduling arrangements for inter-area transactions, once these seams issues are resolved. Rather, the 2008 1,000 MW TSA will be subject to PJM's OATT and, if PJM and NYISO amend the scheduling practice prescribed by their OATTs, the new practice will govern service under the 2008 1,000 MW TSA.

The Commission further finds that no other entity has been unduly discriminated against by denial of substantially similar service on the same terms and conditions as those requested by ConEd, because no entity has requested such service. Rather, the Commission finds that it would be discriminatory to deny ConEd through-and-out service when all other customers are entitled to the service, simply because ConEd sources and sinks its power in the same control area.

- **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 nine months of 2010, the PJM average hourly LMP at the Neptune Interface was $51.98 while the NYISO LMP at the Neptune Bus was $59.68, a difference of $7.69. The average hourly flow during the first nine months of 2010 was -550 MW, which aligned with price differentials in only 56 percent of all hours during the first nine 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 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 nine months of 2010, the PJM average hourly LMP at the Linden Interface was $51.25 while the NYISO LMP at the Linden Bus was $52.83, a difference of $1.58. The average hourly flow during the first nine months of 2010 was -139 MW, which aligned with price differentials in only 58 percent of all hours during the first nine 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 nine months of 2010, net scheduled interchange was -5,845 GWh and net actual interchange was -5,566 GWh for a difference of 279 GWh or 4.8 percent (5.5 percent for the first nine 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). As the net scheduled export levels increased in the second and third 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

29 See PJM. "PJM Open Access Transmission Tariff" (September 17, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (14,838 KB).

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" (September 17, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (14,838 KB).

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 (-10,553 GWh during the first nine months of 2010 and -10,536 GWh during the first nine months of 2009). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (2,794 GWh during the first nine months of 2010 and 2,614 GWh during the first nine 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 nine 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 $4.15 during the first nine 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 nine 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 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 nine months of 2010, PJM issued 96 TLRs. Of the 96 TLRs issued, the highest levels reached were TLR 3a for 56 events and TLR 3b for the remaining 40 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 98 TLRs during the first nine months of 2010, compared to 114 during the first nine 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 September 30, 2010), the monthly average of up-to congestion bids increased from 3,027.1 GWh (for the period from January 1, 2006 through April 30, 2008) to 5,714.6 GWh. In June and July, there was a significant increase in the total up-to congestion bids as shown in Figure 4-23. This increase in activity for up-to congestion transactions was caused by the allocation methodology for the marginal loss surplus.

32 See *2002 State of the Market Report,* Part 2, Section 3, "Interchange Transactions." (March 5, 2003) (Accessed October 15, 2010) <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2002/SOM2002-part2.pdf> (4,068 KB).

The up-to congestion transactions during the first nine months of 2010 were comprised of 47.9 percent imports, 45.2 percent exports and 6.9 percent wheeling transactions. Only 0.1 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, 4.2 percent were imports, 86.9 percent were exports and 8.9 percent were wheel through transactions.

When the up-to congestion product was used as intended, with matching Real-Time Market transactions, 73.3 percent of the total cleared transactions MW were profitable during the first nine months of 2010. The net profit on all these transactions was approximately $396,000. When up-to congestion transactions did not have a matching Real-Time Market transaction, 56.2 percent of the total cleared transactions MW were profitable. The net loss on all these transactions was approximately $38.8 million.

- **Marginal Loss Surplus Allocation.** In an order on complaint, the Commission required PJM to correct an inconsistency in the tariff language defining the method for allocating the marginal loss surplus based on contributions to the fixed costs of the transmission system.[33] On May 15, 2010, PJM implemented the modified method of allocating the marginal loss surplus. As modified, Section 5.5 of the PJM OATT provided that a cleared up-to congestion transaction in the Day-Ahead Energy Market qualified for an allocation of the marginal loss surplus for an hour if that transaction required the purchase of transmission service. Prior to the modification, up-to congestion transactions had not been eligible for an allocation of the marginal loss surplus. However, PJM's tariff modification resulted in an allocation of the marginal loss surplus based on usage of the system rather than based on the dollar contribution to the fixed costs of the transmission system. The inconsistency between the allocation principle defined by FERC and the actual allocation created an incentive for market participants to enter noneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus. These transactions included the submission of up-to congestion wheeling transactions at the same interface, submission of equal and opposite up-to congestion transactions to and from the same internal PJM bus and equal and opposite up-to congestion transactions at buses within the PJM Energy Market that are physically close to one another where the LMP between those buses would be negligible. Market participants engaging in these activities received $17.4 million in marginal loss surplus allocations (with a net profit of $9.5 million after the cost of transmission) during the period of May 15, 2010 through August 31, 2010.

  As a result of this activity, PJM and the MMU presented and discussed proposed short term revisions to the market rules at the August 5, 2010, meeting of the Markets and Reliability Committee and the August 12, 2010, meeting of the Members Committee.[34] PJM proposed to eliminate the requirement for up-to congestion transactions to obtain transmission service and to discount the marginal loss allocation to non-firm transmission service customers. The MMU short term proposal was to cap the marginal loss distribution to any non-firm transmission customer so that the allocations do not exceed the total charges for transmission service. PJM stakeholders voted in favor of the PJM proposal at the August 12, 2010 PJM Members Committee, subject to an agreement to initiate additional stakeholder discussions on a long term solution to the issues. On August 18, 2010, PJM submitted its proposal to the Commission.[35]

  On September 2, 2010, the MMU responded to the PJM filing, explaining that PJM's proposed revisions to the gaming issue were not sufficient to address the underlying problem, the inconsistency between the approved principle and the actual implementation of the method of allocating the marginal loss surplus. [36] The MMU also explained that PJM's proposal would create a spread bidding product, a product type that had been previously proposed and subsequently rejected by PJM participants that would have allowed market participants to take simultaneous positions at two points in the PJM system. The MMU opposed spread bidding because it risked creating opportunities for gaming with no offsetting market benefit. The elimination of the requirement to acquire transmission for up-to congestion transactions creates a spread bidding product that would have either the source or the sink at an interface and the other point anywhere on the PJM system. While limited to either source or sink at an interface, the newly created spread bidding product raises the same issues previously identified with the spread bid product proposals that have previously been rejected by the PJM membership. On September 17, 2010, the Commission approved the PJM revisions as filed on August 18, 2010.[37]

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

34 A copy of the presentations can be viewed at http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-11-marginal-loss-allocation-issue-monitoring-analytics-presentation.ashx and http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-11-marginal-loss-allocation-issue-pjm-presentation.ashx.

35 Docket No. ER10-2280-000.

36 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM." Docket No. ER10-2280-000 (September 2, 2010) (Accessed October 15, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Motion_to_Intervene_and_Comments_ER10-2280-000_20100902.pdf> (329 KB).

37 *PJM Interconnection, L.L.C.* 132 FERC ¶ 61,244.

The Order deferred consideration of the issues raised by the MMU, stating (at P 49):

> [The MMU's] concerns go beyond the scope of this filing and, in effect, argue that PJM has incorrectly implemented the Commission-approved methodology for allocating line losses. While we do not find that these issues should result in the rejection of this filing, they may be considered in the stakeholder process to analyze possible alternatives to PJM's proposed changes to which PJM are committed, including *inter alia* the various issues raised by Monitoring Analytics.

PJM created the "Transactions Issues Task Force" to address the deferred issues and to evaluate the allocation of the marginal loss surplus.

- **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 nine months of 2010 were approximately $2.9 Million ($272,651 for the first nine 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. On August 16, 2010, PJM modified the EES application to automatically detect and modify not willing to pay congestion transactions, prior to their start, when system LMPs at the transactions' identified source and sink differ. This functionality will prevent not willing to pay congestion transactions from starting in those instances by automatically issuing curtailment requests. The same evaluation is performed on not willing to pay congestion transactions that have already been loaded, and will curtail those transactions at the next applicable 15 minute interval. These changes will reduce the amount of uncollected congestion charges by eliminating the previously utilized manual intervention for curtailments and reducing the potential for not willing to pay congestion transactions to continue to flow, undetected. While the recent EES modifications automate the process for identifying those instances, the timing requirements for curtailing transactions requires that the evaluation be done with 20 minutes notice prior to the start of the transaction. There is still the potential for not willing to pay congestion transactions to begin in cases when congestion exists prior to the transaction start time but after the evaluation. When this occurs, the transaction will be curtailed at the next applicable 15 minute interval.

  The MMU recommends that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service; and restricting the use of not willing to pay congestion transactions to wheeling transactions across the PJM footprint.

  The not willing to pay congestion product was originally offered to market participants in order to limit their exposure to congestion at a time when market participants could only modify their transactions with 60 minutes notice. This is no longer the case. Market participants can now modify their transactions at any 15 minute interval with 20 minutes notice. Thus, the underlying rationale for the product no longer exists. Use of this product eliminates the need for 24 hour monitoring, as PJM automatically curtails not willing to pay congestion transactions as soon as possible when congestion is realized. PJM provides a service to market participants in minimizing the exposure to congestion charges for not willing to pay congestion transactions, and market participants who elect to utilize not willing to pay congestion transmission should be willing to pay the minimized congestion charges. The MMU also recommends limiting the use of not willing to pay congestion transactions to wheeling transactions only. It is not possible to control the flow of energy from an external interface to an internal bus within the PJM footprint. 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.

- **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 congestion 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 nine months of 2010, including evolving transaction patterns, economics and issues. During the first nine 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 70 percent of the total real-time net exports and two interfaces accounted for 87 percent of the real-time net import volume. Four interfaces accounted for 89 percent of the total day-ahead net exports and two interfaces accounted for 71 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.

In the third quarter of 2010, some market participants were observed entering uneconomic up to congestion transactions for the sole purpose of taking advantage of the revised marginal loss surplus allocation methodology. Some market participants took advantage of the fact that up to congestion transactions offered the flexibility to specify any import or export pricing point, regardless of the associated transmission path, and that up to congestion transactions became eligible to receive marginal loss surplus allocations, where they previously were ineligible. The MMU believes that this issue arose due to a flaw in the implemented marginal loss surplus allocation, and that if PJM modifies the methodology to comport with the Commission's directive to allocate marginal losses based on a pro rata share of market participants' contributions to the fixed costs of the transmission system, the incentives to submit uneconomic transactions would be eliminated, and the marginal loss surplus allocations would be distributed in the most equitable manner.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through September 2010 (See 2009 SOM, Figure 4-1)

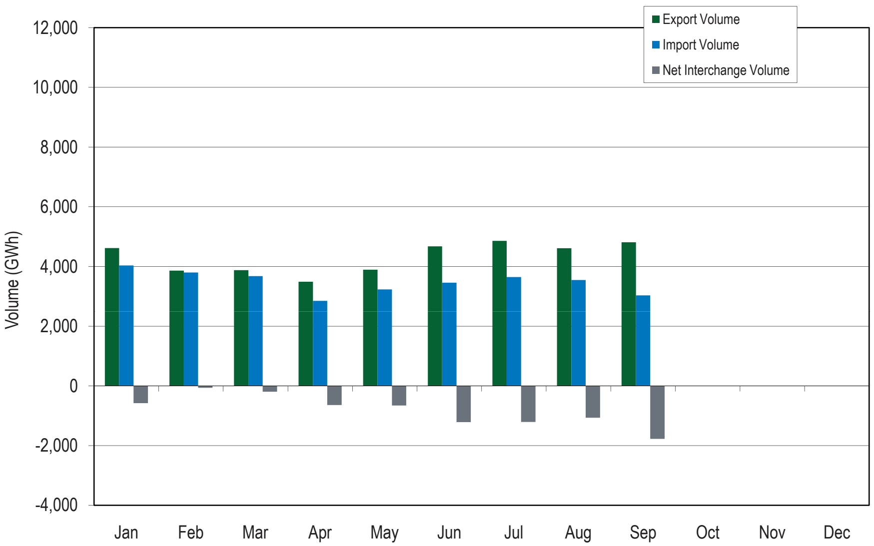


Figure 4-2 PJM day-ahead scheduled imports and exports: January through September 2010 (See 2009 SOM, Figure 4-2)

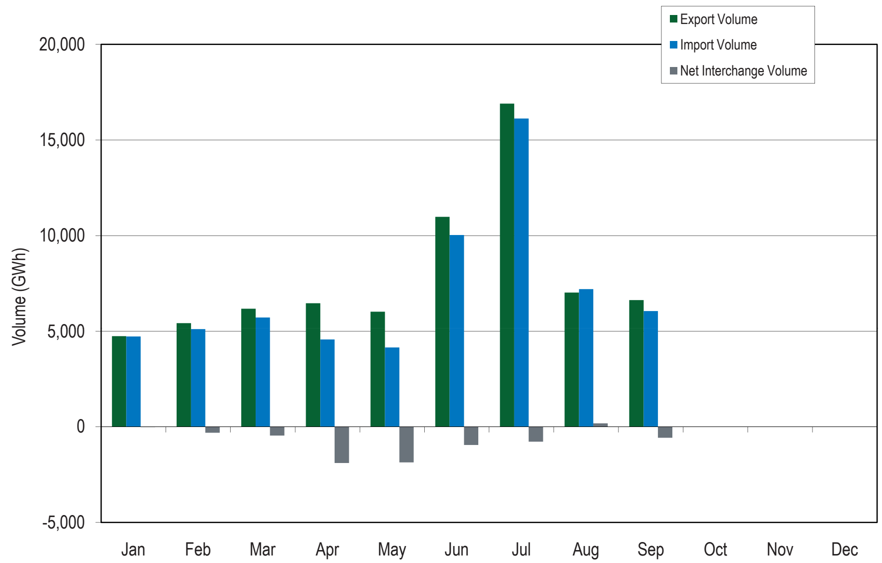
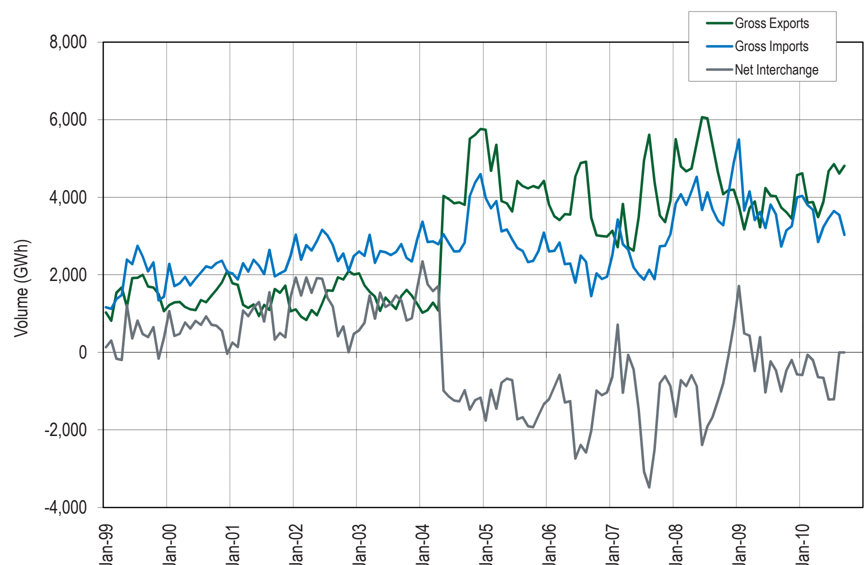


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through September 2010 (See 2009 SOM, Figure 4-3)



Interface Imports and Exports

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

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(70.4)	(72.8)	(40.8)	(141.2)	(114.0)	(154.2)	(150.1)	(162.4)	(154.8)	(1,060.7)
CPLW	0.0	0.0	0.0	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)	(50.8)	(21.0)	(113.3)	78.3
EKPC	(65.5)	(99.2)	14.1	39.3	(0.2)	(19.5)	81.2	88.4	(43.5)	(4.9)
LGEE	31.9	144.5	29.7	44.1	116.8	130.0	160.3	103.4	185.4	946.1
MEC	(454.2)	(422.0)	(458.1)	(383.0)	(436.0)	(429.4)	(440.7)	(402.4)	(420.2)	(3,846.0)
MISO	(74.1)	512.4	510.7	8.1	188.5	(327.7)	(658.1)	(550.5)	(945.7)	(1,336.4)
ALTE	3.6	(9.5)	13.7	(7.1)	(0.7)	(66.2)	(90.3)	(46.3)	(116.0)	(318.8)
ALTW	(32.1)	(8.4)	1.4	(16.1)	(27.7)	(148.3)	(80.2)	(54.7)	(106.3)	(472.4)
AMIL	(141.6)	(85.5)	(63.5)	(25.6)	37.1	18.8	22.1	77.6	(7.4)	(168.0)
CIN	78.4	323.4	233.5	(112.2)	189.0	155.8	(37.8)	(52.3)	(333.5)	444.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(13.8)	(13.8)
FE	(117.4)	(60.2)	(70.6)	(114.3)	(142.5)	(173.5)	(182.1)	(211.3)	(86.1)	(1,158.0)
IPL	(28.4)	48.4	(4.6)	112.6	61.3	(61.2)	(177.9)	(121.3)	(170.1)	(341.2)
MECS	195.1	312.7	387.5	199.7	95.9	103.2	34.9	0.5	20.1	1,349.6
NIPS	(24.0)	(10.8)	(4.9)	(0.6)	(1.9)	(111.1)	(98.2)	(49.9)	(56.7)	(358.1)
WEC	(7.7)	2.3	18.2	(28.3)	(22.0)	(45.2)	(48.6)	(92.8)	(75.9)	(300.0)
NYISO	(1,307.0)	(1,039.9)	(1,109.6)	(950.3)	(1,334.9)	(1,257.1)	(1,003.0)	(1,029.6)	(1,219.8)	(10,251.2)
LIND	(146.0)	(125.5)	(115.7)	(75.8)	(89.8)	(100.4)	(99.2)	(63.6)	(113.0)	(929.0)
NEPT	(496.7)	(423.6)	(449.9)	(280.9)	(464.8)	(466.6)	(411.5)	(292.7)	(375.7)	(3,662.4)
NYIS	(664.3)	(490.8)	(544.0)	(593.6)	(780.3)	(690.1)	(492.3)	(673.3)	(731.1)	(5,659.8)
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	781.7	1,004.6	931.1	8,517.9
TVA	(39.0)	(121.5)	(129.3)	(88.3)	(7.8)	(43.4)	69.0	(97.4)	2.7	(455.0)
Total	(581.7)	(63.3)	(197.3)	(640.2)	(658.1)	(1,215.8)	(1,210.5)	(1,066.9)	(1,778.1)	(7,411.9)

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

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	128.3	113.4	99.8	0.6	22.7	9.9	28.2	26.5	6.4	435.8
CPLW	0.0	0.0	0.0	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	229.5	243.7	104.5	1,932.5
EKPC	15.8	3.0	53.9	58.1	34.8	36.6	88.9	104.2	22.6	417.9
LGEE	48.9	150.5	73.5	58.7	135.6	161.8	187.6	171.8	218.2	1,206.6
MEC	44.1	28.1	35.7	52.3	61.5	34.7	41.7	46.5	43.7	388.3
MISO	1,142.9	1,388.4	1,292.1	852.6	907.3	1,055.0	866.6	748.7	656.4	8,910.0
ALTE	30.0	8.0	28.9	2.4	9.4	1.0	1.3	6.7	3.3	91.0
ALTW	0.0	5.4	7.6	1.1	2.8	6.3	7.6	17.6	14.5	62.9
AMIL	23.5	49.2	39.2	45.6	55.0	37.1	33.3	88.8	17.3	389.0
CIN	500.9	555.4	454.8	227.2	364.7	551.6	366.0	314.9	216.4	3,551.9
CWLP	0.0	0.0	0.0	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	176.9	150.8	218.3	1,606.4
IPL	47.1	116.7	16.2	115.9	113.5	71.8	16.0	1.5	4.3	503.0
MECS	304.3	385.9	475.1	283.7	181.5	185.2	215.2	150.5	170.9	2,352.3
NIPS	0.0	0.0	0.0	0.2	13.4	6.4	2.9	14.7	10.8	48.4
WEC	55.5	60.2	64.9	20.5	19.5	33.3	47.4	3.2	0.6	305.1
NYISO	934.4	901.2	922.5	765.7	890.8	916.1	1,184.7	1,084.6	916.6	8,516.6
LIND	0.0	0.0	0.0	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	0.0	0.0	0.0
NYIS	934.4	901.2	922.5	765.7	890.8	916.1	1,184.7	1,084.6	916.6	8,516.6
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	781.7	1,004.6	931.1	8,517.9
TVA	134.6	35.7	47.7	63.0	115.6	67.9	237.4	116.4	131.8	950.1
Total	4,034.4	3,798.5	3,679.1	2,847.6	3,232.8	3,458.7	3,646.3	3,547.0	3,031.3	31,275.7

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

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	198.7	186.2	140.6	141.8	136.7	164.1	178.3	188.9	161.2	1,496.5
CPLW	0.0	0.0	0.0	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	280.3	264.7	217.8	1,854.2
EKPC	81.3	102.2	39.8	18.8	35.0	56.1	7.7	15.8	66.1	422.8
LGEE	17.0	6.0	43.8	14.6	18.8	31.8	27.3	68.4	32.8	260.5
MEC	498.3	450.1	493.8	435.3	497.5	464.1	482.4	448.9	463.9	4,234.3
MISO	1,217.0	876.0	781.4	844.5	718.8	1,382.7	1,524.7	1,299.2	1,602.1	10,246.4
ALTE	26.4	17.5	15.2	9.5	10.1	67.2	91.6	53.0	119.3	409.8
ALTW	32.1	13.8	6.2	17.2	30.5	154.6	87.8	72.3	120.8	535.3
AMIL	165.1	134.7	102.7	71.2	17.9	18.3	11.2	11.2	24.7	557.0
CIN	422.5	232.0	221.3	339.4	175.7	395.8	403.8	367.2	549.9	3,107.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.8	13.8
FE	299.0	267.8	276.0	270.3	290.0	335.8	359.0	362.1	304.4	2,764.4
IPL	75.5	68.3	20.8	3.3	52.2	133.0	193.9	122.8	174.4	844.2
MECS	109.2	73.2	87.6	84.0	85.6	82.0	180.3	150.0	150.8	1,002.7
NIPS	24.0	10.8	4.9	0.8	15.3	117.5	101.1	64.6	67.5	406.5
WEC	63.2	57.9	46.7	48.8	41.5	78.5	96.0	96.0	76.5	605.1
NYISO	2,241.4	1,941.1	2,032.1	1,716.0	2,225.7	2,173.2	2,187.7	2,114.2	2,136.4	18,767.8
LIND	146.0	125.5	115.7	75.8	89.8	100.4	99.2	63.6	113.0	929.0
NEPT	496.7	423.6	449.9	280.9	464.8	466.6	411.5	292.7	375.7	3,662.4
NYIS	1,598.7	1,392.0	1,466.5	1,359.3	1,671.1	1,606.2	1,677.0	1,757.9	1,647.7	14,176.4
OVEC	0.0	0.0	0.0	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	168.4	213.8	129.1	1,405.1
Total	4,616.1	3,861.8	3,876.4	3,487.8	3,890.9	4,674.5	4,856.8	4,613.9	4,809.4	38,687.6

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

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(89.3)	(111.3)	(114.7)	(122.2)	(108.3)	(134.2)	372.0	(119.5)	(70.8)	(498.3)
CPLW	10.2	(1.0)	1.0	(0.9)	(1.0)	(1.5)	6.7	2.0	5.6	21.1
DUK	161.4	38.4	8.6	12.6	72.5	23.2	(222.7)	(100.4)	29.2	372.2
EKPC	(1.5)	(5.9)	(3.4)	(0.2)	(1.4)	(3.0)	(4.5)	(3.5)	(0.1)	(59.9)
LGEE	1.0	5.3	0.0	(0.1)	1.4	(8.0)	(13.7)	(51.5)	(3.7)	(20.8)
MEC	(479.4)	(444.1)	(482.8)	(433.0)	(464.1)	(789.0)	(374.3)	(457.0)	(448.1)	(2,824.3)
MISO	282.3	(160.5)	(312.1)	(1,450.5)	(1,018.5)	550.4	3,478.1	820.5	79.0	2,268.7
ALTE	227.6	(257.5)	(136.2)	(302.4)	(711.0)	(168.0)	73.0	145.9	(9.0)	(1,137.6)
ALTW	(282.2)	(414.3)	(1,220.9)	(1,761.3)	(766.8)	(2,195.9)	(1,908.2)	(567.7)	68.1	(9,049.2)
AMIL	14.4	97.5	6.7	12.4	44.5	114.6	1.7	9.0	(1.3)	299.5
CIN	182.9	(60.8)	43.1	(70.3)	41.8	310.0	1,376.9	161.3	4.2	1,989.1
CWLP	0.0	0.0	0.0	0.0	(0.3)	0.0	(19.5)	0.0	(11.8)	(31.6)
FE	(70.5)	(20.7)	118.8	(72.4)	(79.3)	390.4	1,007.5	20.4	(218.3)	1,075.9
IPL	(53.4)	(18.4)	(44.7)	(8.5)	(42.0)	68.9	131.8	41.7	(41.0)	34.4
MECS	387.8	654.4	885.6	732.9	546.6	1,223.9	1,484.6	767.5	379.5	7,062.8
NIPS	(204.5)	(217.0)	(143.3)	(87.6)	(120.2)	(103.9)	394.9	(34.3)	(67.1)	(583.0)
WEC	80.2	76.3	178.8	106.7	68.2	910.4	935.4	276.7	(24.3)	2,608.4
NYISO	(969.0)	(912.0)	(825.4)	(752.7)	(1,017.9)	(1,657.9)	(4,727.8)	(904.8)	(894.0)	(12,661.5)
LIND	(21.1)	(18.3)	(53.2)	(11.4)	(15.3)	(12.0)	(24.7)	(9.9)	(53.2)	(219.1)
NEPT	(502.6)	(445.2)	(456.7)	(301.3)	(473.4)	(472.7)	(420.9)	(317.7)	(374.8)	(3,765.3)
NYIS	(445.3)	(448.5)	(315.5)	(440.0)	(529.2)	(1,173.2)	(4,282.2)	(577.2)	(466.0)	(8,677.1)
OVEC	1,074.0	1,243.3	1,300.5	917.1	679.0	1,058.2	1,045.7	978.5	711.5	9,007.8
TVA	(5.3)	37.8	(27.0)	(60.9)	(5.4)	7.7	(335.1)	16.4	18.0	(353.8)
Total	(15.6)	(310.0)	(455.3)	(1,890.8)	(1,863.7)	(954.1)	(775.6)	180.7	(573.4)	(6,657.8)

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

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	64.2	39.5	29.3	10.7	15.8	49.1	595.7	124.6	89.2	1,018.1
CPLW	15.6	0.6	1.8	0.0	1.4	0.8	6.7	2.0	7.1	36.0
DUK	176.3	96.2	48.1	40.2	107.2	77.8	139.9	112.9	108.6	907.2
EKPC	0.0	0.0	0.4	0.0	0.0	0.0	0.2	0.0	0.0	0.6
LGEE	1.0	5.4	0.0	0.0	1.8	0.5	1.4	6.5	2.2	18.8
MEC	18.8	5.6	12.2	18.6	70.2	158.8	247.8	33.6	20.7	586.3
MISO	2,400.5	2,738.3	3,112.5	2,678.8	2,251.6	7,455.1	12,488.8	4,596.2	3,905.6	41,627.4
ALTE	866.4	762.4	662.8	382.9	263.8	721.2	2,191.6	1,241.3	1,728.4	8,820.8
ALTW	72.0	67.2	72.4	53.6	40.2	345.7	896.3	257.6	542.7	2,347.7
AMIL	68.1	157.9	50.5	32.1	44.8	114.6	1.7	10.5	4.5	484.7
CIN	436.8	592.0	555.1	590.4	430.6	969.6	1,988.3	701.1	238.3	6,502.2
CWLP	0.0	0.0	0.0	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	1,536.1	519.1	204.8	4,093.7
IPL	26.9	29.4	30.7	102.8	97.0	1,045.3	1,004.8	124.0	16.8	2,477.7
MECS	606.2	801.7	1,125.2	1,118.7	1,035.2	2,223.8	2,629.9	1,246.7	1,060.7	11,848.1
NIPS	28.6	19.5	24.3	33.1	26.9	292.1	1,115.1	84.5	19.3	1,643.4
WEC	139.3	131.3	226.6	161.5	133.8	990.1	1,125.0	411.4	90.1	3,409.1
NYISO	835.3	885.1	1,095.7	883.7	858.1	1,165.0	1,202.9	1,219.8	1,047.4	9,193.0
LIND	0.0	0.0	0.0	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	0.0	0.0	0.0
NYIS	835.3	885.1	1,095.7	883.7	858.1	1,165.0	1,202.9	1,219.8	1,047.4	9,193.0
OVEC	1,133.2	1,259.7	1,379.9	922.0	802.1	1,063.8	1,086.8	985.3	793.4	9,426.2
TVA	75.9	77.8	36.7	15.2	44.4	55.3	357.2	120.3	79.1	861.9
Total	4,720.8	5,108.2	5,716.6	4,569.2	4,152.6	10,026.2	16,127.4	7,201.2	6,053.3	63,675.5

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

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	153.5	150.8	144.0	132.9	124.1	183.3	223.7	244.1	160.0	1,516.4
CPLW	5.4	1.6	0.8	0.9	2.4	2.3	0.0	0.0	1.5	14.9
DUK	14.9	57.8	39.5	27.6	34.7	54.6	362.6	213.3	79.4	535.0
EKPC	1.5	5.9	3.8	0.2	1.4	3.0	4.7	3.5	0.1	60.5
LGEE	0.0	0.1	0.0	0.1	0.4	8.5	15.1	58.0	5.9	39.6
MEC	498.2	449.7	495.0	451.6	534.3	947.8	622.1	490.6	468.8	3,410.6
MISO	2,118.2	2,898.8	3,424.6	4,129.3	3,270.1	6,904.7	9,010.7	3,775.7	3,826.6	39,358.7
ALTE	638.8	1,019.9	799.0	685.3	974.8	889.2	2,118.6	1,095.4	1,737.4	9,958.4
ALTW	354.2	481.5	1,293.3	1,814.9	807.0	2,541.6	2,804.5	825.3	474.6	11,396.9
AMIL	53.7	60.4	43.8	19.7	0.3	0.0	0.0	1.5	5.8	185.2
CIN	253.9	652.8	512.0	660.7	388.8	659.6	611.4	539.8	234.1	4,513.1
CWLP	0.0	0.0	0.0	0.0	0.3	0.0	19.5	0.0	11.8	31.6
FE	226.7	197.6	246.1	276.1	258.6	362.3	528.6	498.7	423.1	3,017.8
IPL	80.3	47.8	75.4	111.3	139.0	976.4	873.0	82.3	57.8	2,443.3
MECS	218.4	147.3	239.6	385.8	488.6	999.9	1,145.3	479.2	681.2	4,785.3
NIPS	233.1	236.5	167.6	120.7	147.1	396.0	720.2	118.8	86.4	2,226.4
WEC	59.1	55.0	47.8	54.8	65.6	79.7	189.6	134.7	114.4	800.7
NYISO	1,804.3	1,797.1	1,921.1	1,636.4	1,876.0	2,822.9	5,930.7	2,124.6	1,941.4	21,854.5
LIND	21.1	18.3	53.2	11.4	15.3	12.0	24.7	9.9	53.2	219.1
NEPT	502.6	445.2	456.7	301.3	473.4	472.7	420.9	317.7	374.8	3,765.3
NYIS	1,280.6	1,333.6	1,411.2	1,323.7	1,387.3	2,338.2	5,485.1	1,797.0	1,513.4	17,870.1
OVEC	59.2	16.4	79.4	4.9	123.1	5.6	41.1	6.8	81.9	418.4
TVA	81.2	40.0	63.7	76.1	49.8	47.6	692.3	103.9	61.1	1,215.7
Total	4,736.4	5,418.2	6,171.9	6,460.0	6,016.3	10,980.3	16,903.0	7,020.5	6,626.7	70,333.3

Interface Pricing

Table 4-7 Active interfaces: January through September 2010 (See 2009 SOM, Table 4-7)

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

Figure 4-4 PJM's footprint and its external interfaces (See 2009 SOM, Figure 4-4)

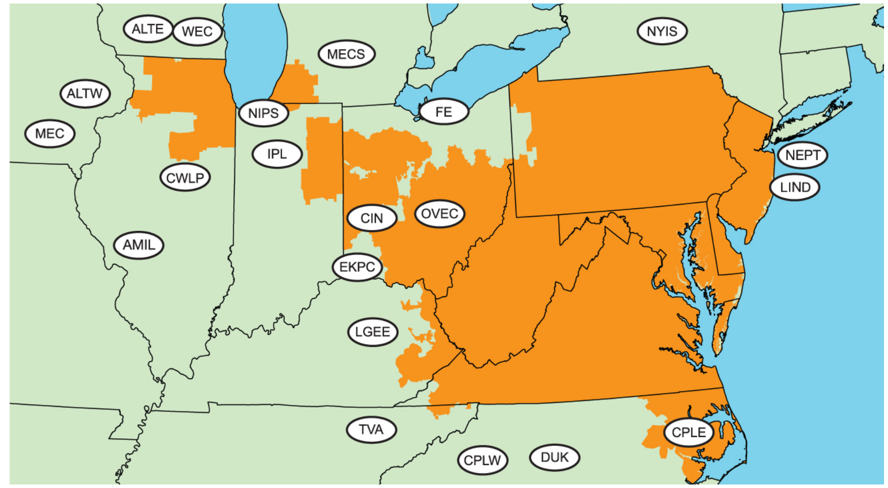


Table 4-8 Active pricing points: January through September 2010 (See 2009 SOM, Table 4-8)

PJM 2010 Pricing Points (January through September)			
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 September 2010 (See 2009 SOM, Figure 4-5)

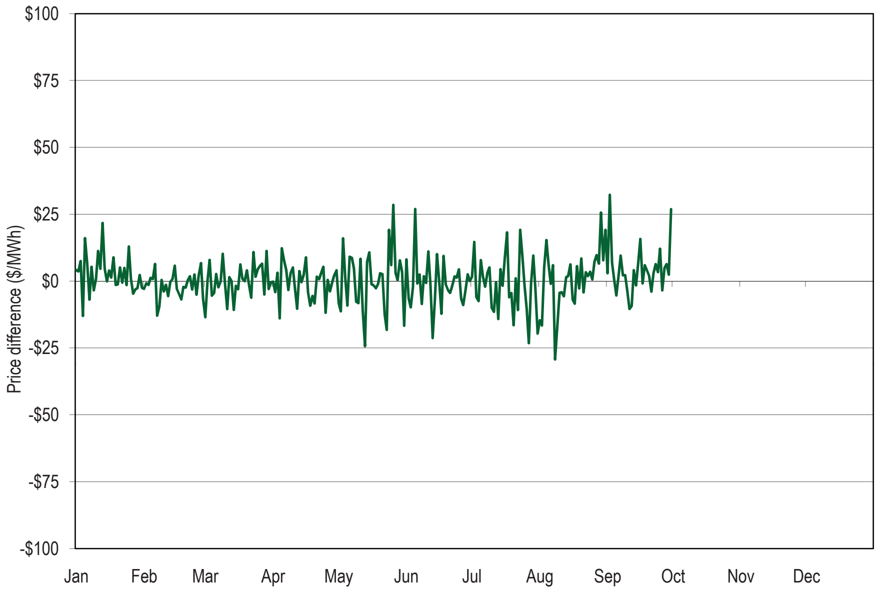


Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2010 (See 2009 SOM, Figure 4-6)

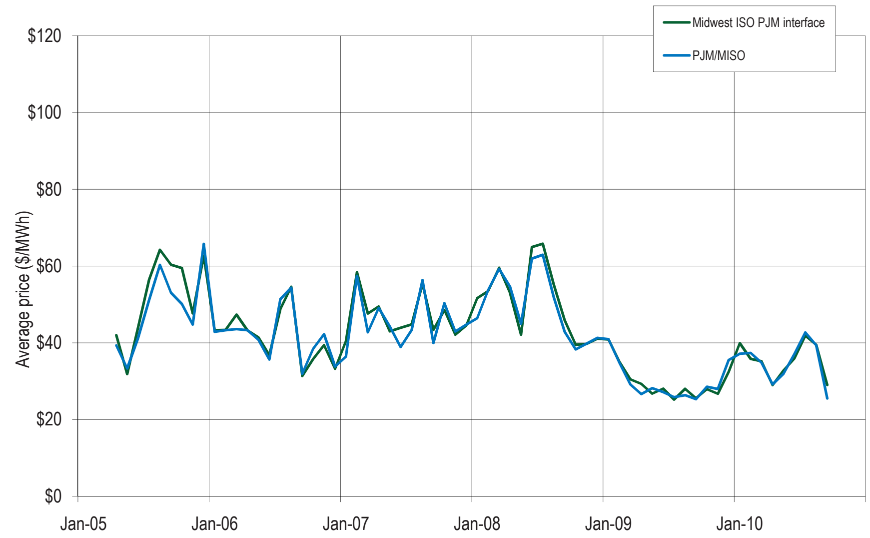


Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): January 2008 through September 2010 (See 2009 SOM, Table 4-9)

	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)	$3.18	($6.66)	($2.70)
Beaver Valley (PJM) & Mansfield (MISO)	$0.89	($14.42)	($2.38)	$3.22	($4.92)	($1.38)	$2.41	($8.23)	($1.90)
Miami Fort (PJM) & (MISO)	$1.25	($12.27)	($4.16)	$2.20	($4.64)	($2.70)	$1.87	($4.82)	($3.41)
Stuart (PJM) & (MISO)	$0.87	($12.04)	($4.77)	$1.81	($4.63)	($3.07)	$1.77	($6.97)	($3.80)
PJM/MISO Interface	($1.16)	($15.34)	($3.51)	$0.01	($6.94)	($2.58)	($0.37)	($9.70)	($3.21)

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 September 2010 (See 2009 SOM, Figure 4-7)

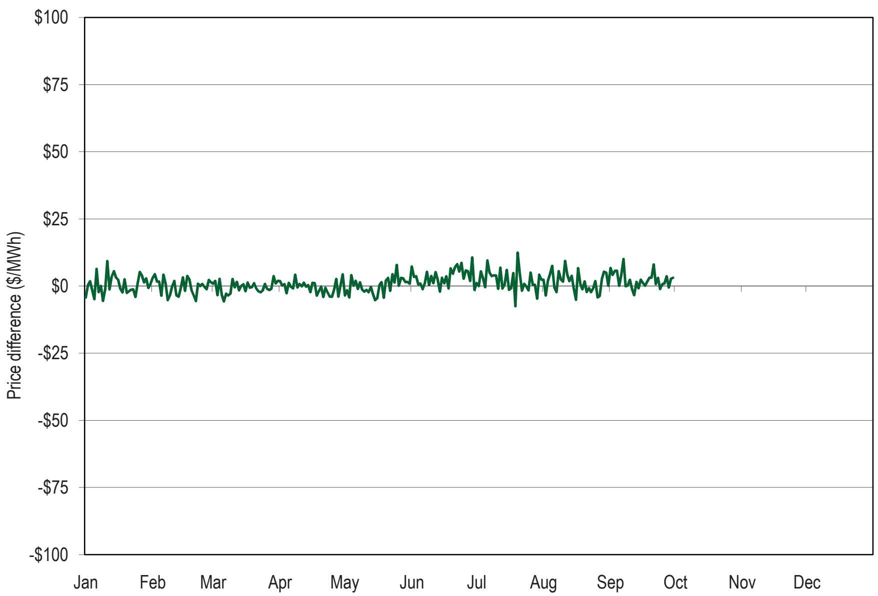


Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2010 (See 2009 SOM, Figure 4-8)

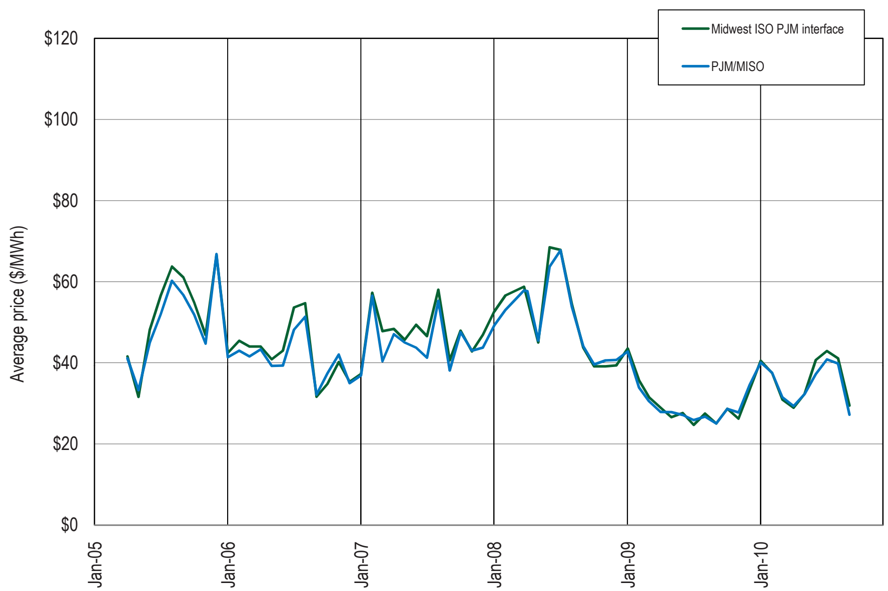


Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): January 2008 through September 2010 (See 2009 SOM, Table 4-10)

	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)	$1.86	($5.87)	($3.31)
Beaver Valley (PJM) & Mansfield (MISO)	$3.40	($9.88)	($3.16)	$2.48	($4.72)	($1.67)	$1.84	($6.82)	($2.38)
Miami Fort (PJM) & (MISO)	($0.05)	($11.17)	($5.32)	$1.87	($3.85)	($3.16)	$0.68	($6.09)	($4.26)
Stuart (PJM) & (MISO)	($0.56)	($11.00)	($6.00)	$1.40	($3.87)	($3.61)	$0.35	($5.95)	($4.74)
PJM/MISO Interface	($0.62)	($12.51)	($4.55)	($0.03)	($5.75)	($3.16)	($0.95)	($7.84)	($4.15)
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 September 2010 (See 2009 SOM, Figure 4-9)

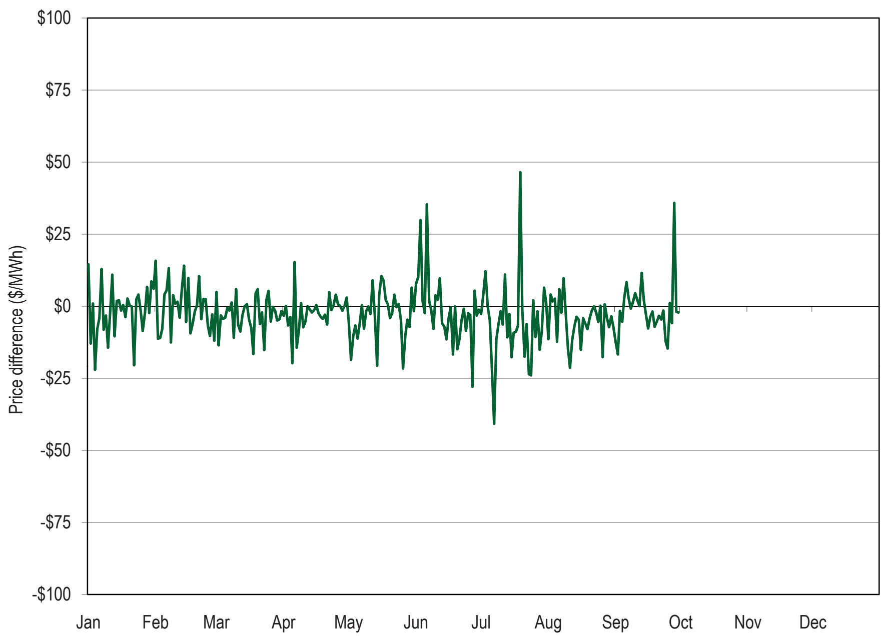


Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through September 2010 (See 2009 SOM, Figure 4-10)

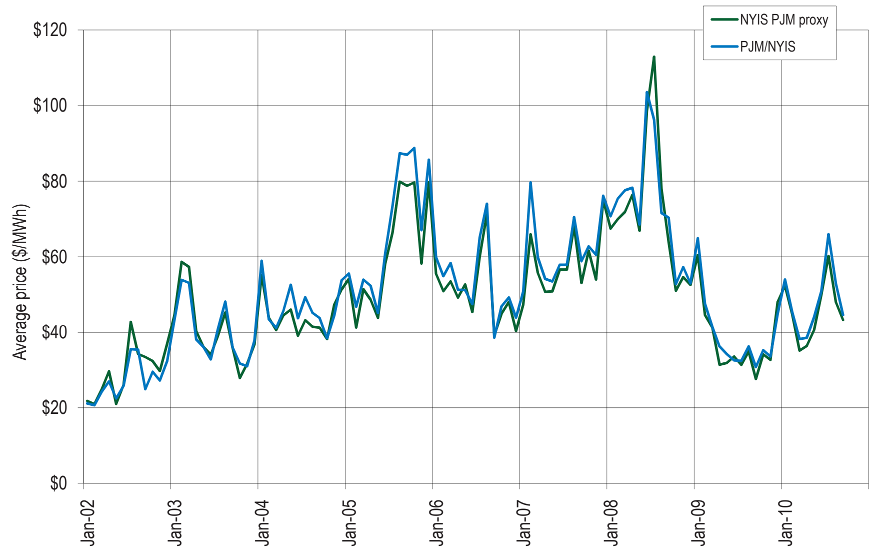


Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through September 2010 (See 2009 SOM, Figure 4-11)

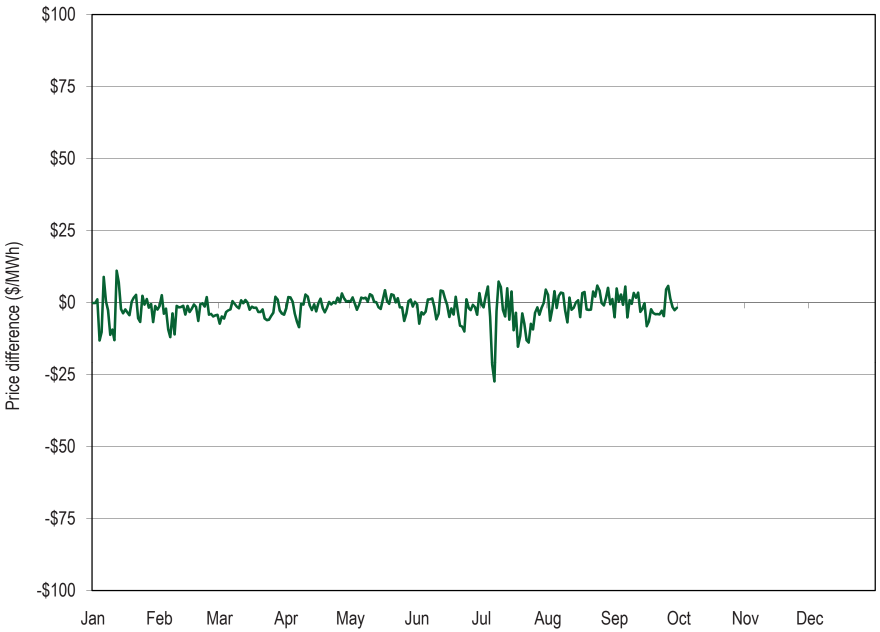
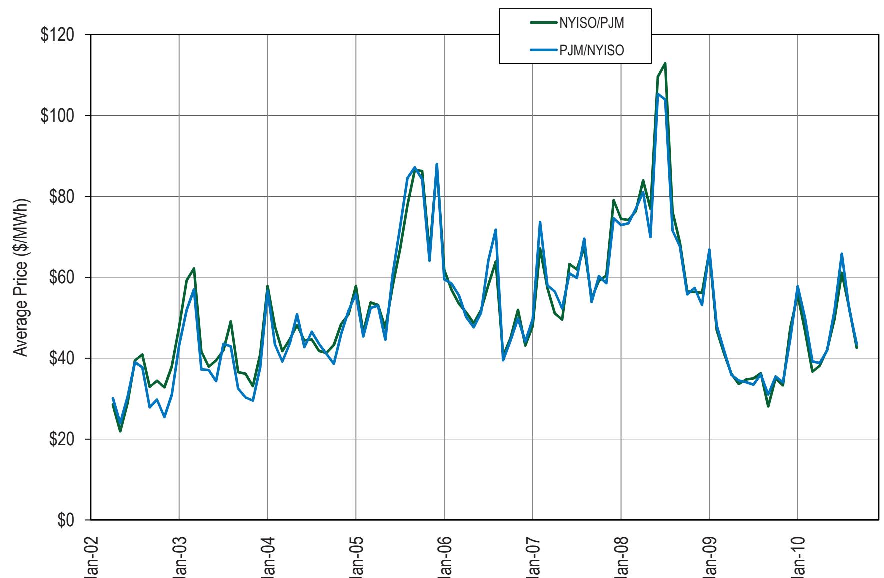


Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through September 2010 (See 2009 SOM, Figure 4-12)



Summary of Interface Prices between PJM and Organized Markets

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

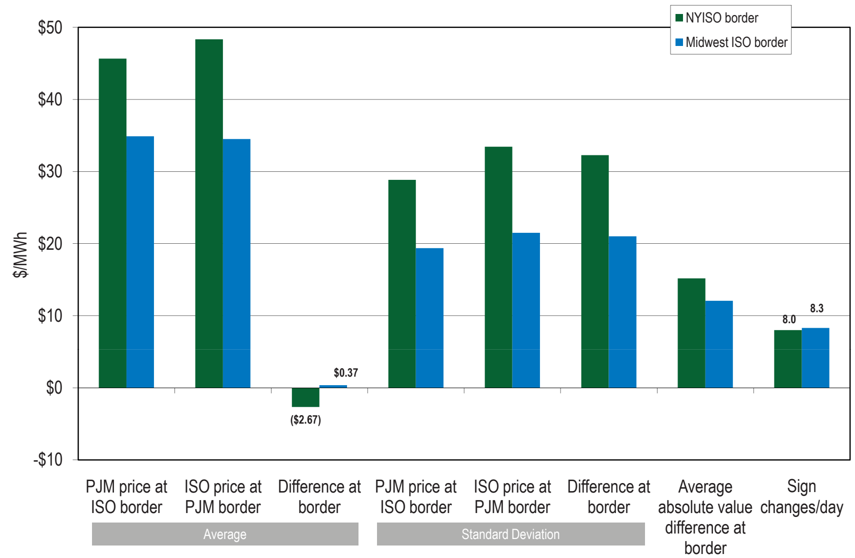
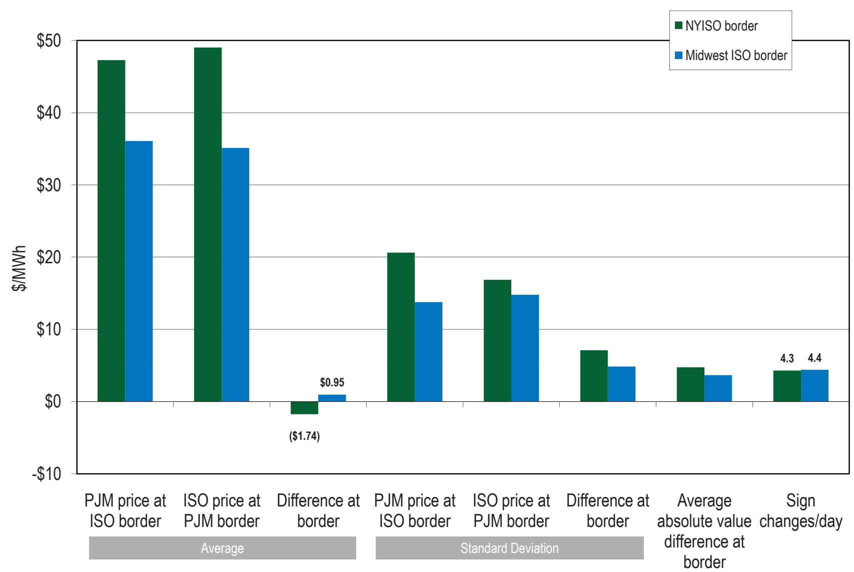


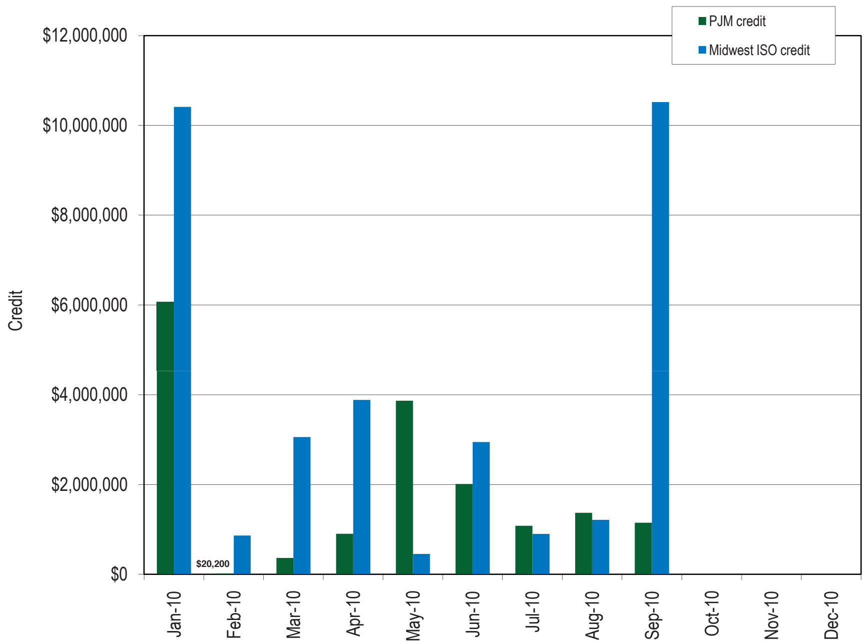
Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: January through September 2010 (See 2009 SOM, Figure 4-14)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement

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



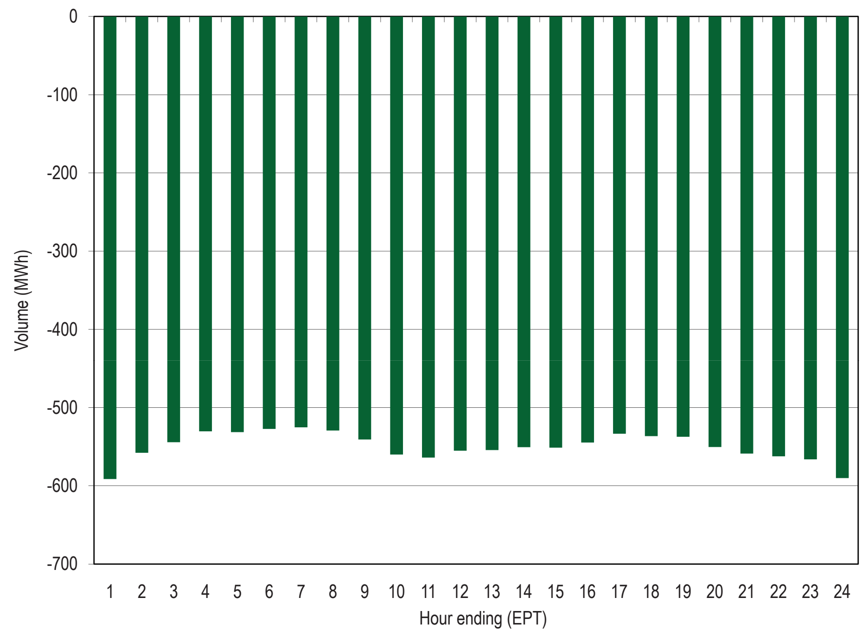
Con Edison and PSE&G Wheeling Contracts

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

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total	Congestion Charge	$3,721,574	($26,966)	$3,694,608	$6,031,780	$0	$6,031,780
	Congestion Credit			$2,042,635			$5,344,584
	Adjustments			$16,175			$351,387
	Net Charge			$1,635,798			$335,809

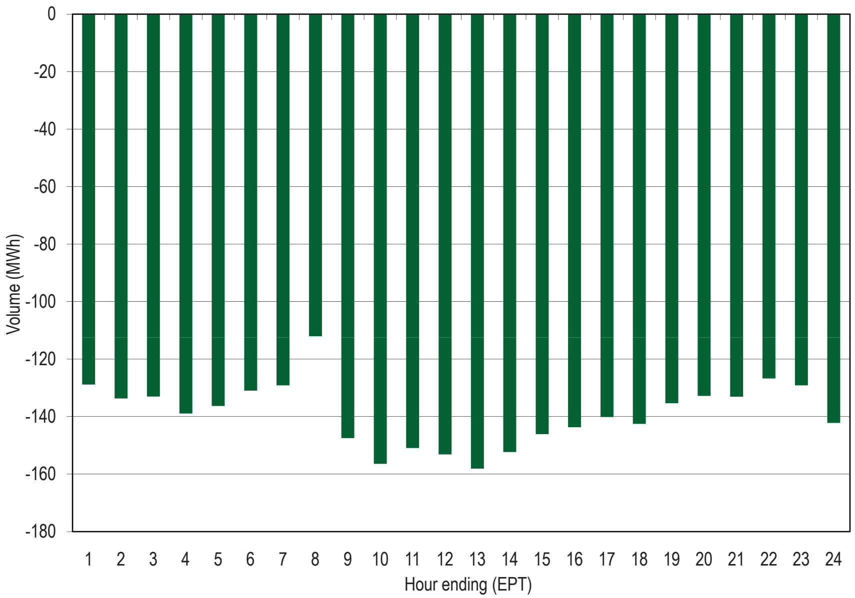
Neptune Underwater Transmission Line to Long Island, New York

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



Linden Variable Frequency Transformer (VFT) facility

Figure 4-17 Linden hourly average flow: January through September 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 September 2010 (See 2009 SOM, Table 4-12)

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	5,910	(182)	6,092	(3,347%)
CPLW	(1,434)	-	(1,434)	0%
DUK	(2,325)	80	(2,405)	(3,006%)
EKPC	675	-	675	0%
LGEE	917	949	(32)	(3%)
MEC	(1,963)	(3,856)	1,893	(49%)
MISO	(5,784)	(399)	(5,385)	1,350%
ALTE	(4,304)	(319)	(3,985)	1,249%
ALTW	(1,562)	(473)	(1,089)	230%
AMIL	4,568	(236)	4,804	(2,036%)
CIN	1,126	2,293	(1,167)	(51%)
CWLP	(194)	(14)	(180)	1,286%
FE	(610)	(1,954)	1,344	(69%)
IPL	2,120	(397)	2,517	(634%)
MECS	(9,193)	1,360	(10,553)	(776%)
NIPS	(1,698)	(358)	(1,340)	374%
WEC	3,963	(301)	4,264	(1,417%)
NYISO	(8,871)	(10,325)	1,454	(14%)
LIND	(910)	(910)	-	0%
NEPT	(3,601)	(3,601)	-	0%
NYIS	(4,360)	(5,814)	1,454	(25%)
OVEC	5,178	8,551	(3,373)	(39%)
TVA	2,131	(663)	2,794	(421%)
Total	(5,566)	(5,845)	279	(4.8%)

Loop Flows at PJM's Southern Interfaces

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

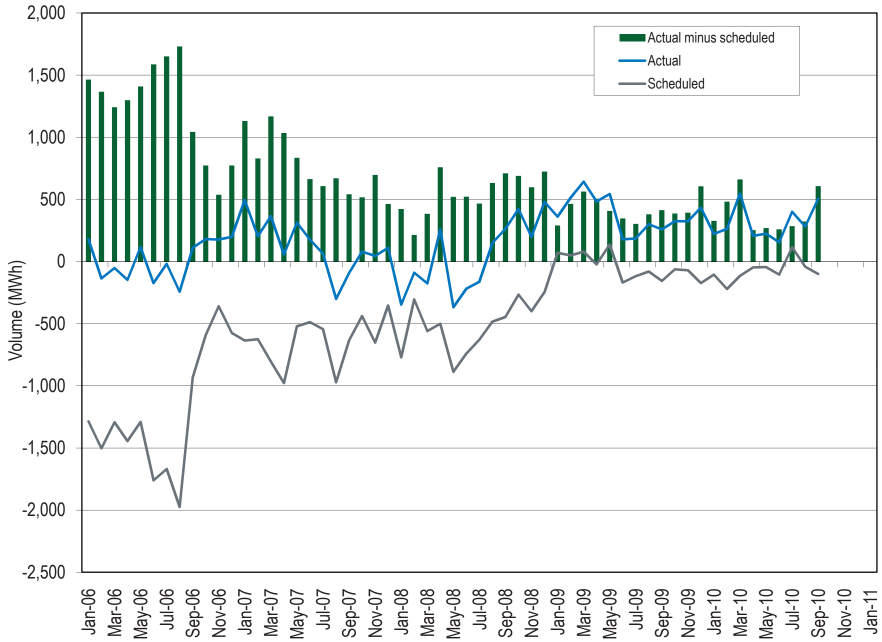
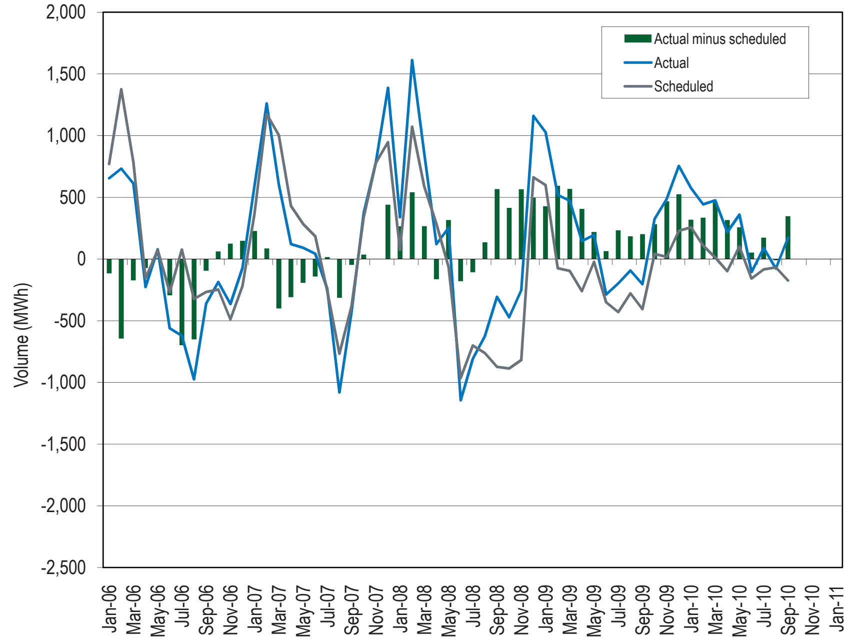


Figure 4-19 Southeast actual and scheduled flows: January 2006 through September 2010 (See 2009 SOM, Figure 4-19)



TLRs

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

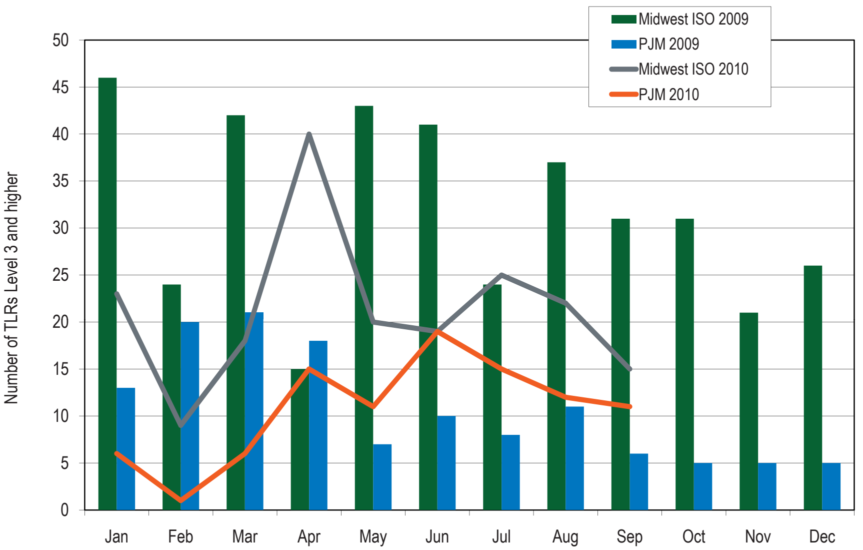


Figure 4-21 Number of different PJM flowgates that experienced TLRs: Calendar year 2009 and January through September 2010 (See 2009 SOM, Figure 4-21)

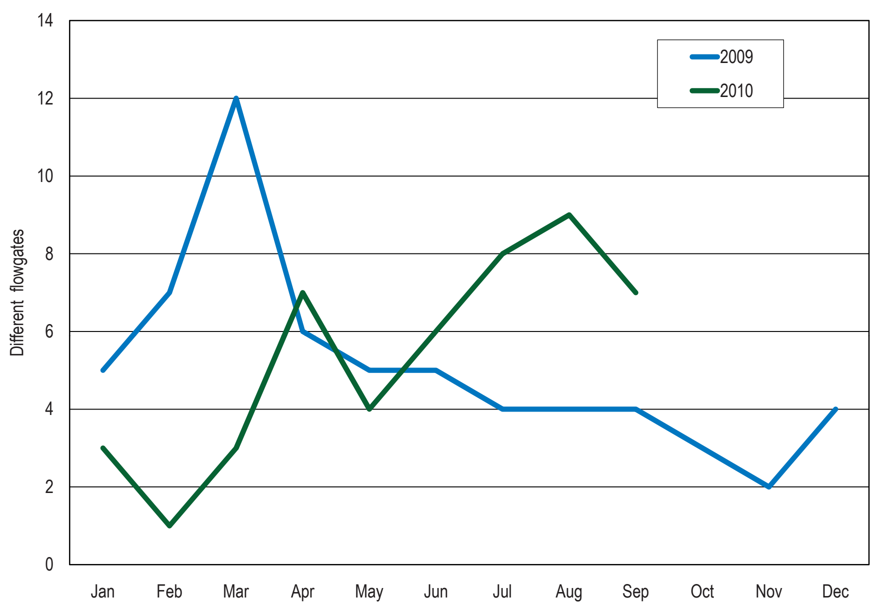


Figure 4-22 Number of PJM TLRs and curtailed volume: January through September 2010 (See 2009, Figure 4-22)

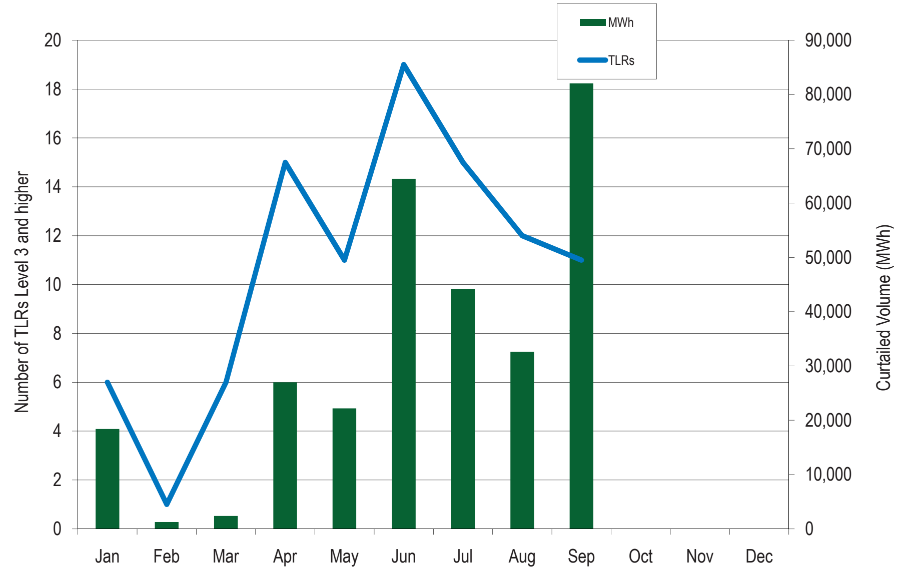


Table 4-13 Number of TLRs by TLR level by reliability coordinator: January through September 2010 (See 2009 SOM, Table 4-13)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2010	ICTE	67	23	141	43	30	0	304
	MISO	102	59	0	14	16	0	191
	NYIS	99	0	0	0	0	0	99
	ONT	62	5	0	1	0	0	68
	PJM	56	40	0	0	0	0	96
	SWPP	183	950	19	51	26	0	1,229
	TVA	13	27	7	0	1	0	48
	VACS	1	1	0	0	0	0	2
Total		583	1,105	167	109	73	0	2,037

Up-To Congestion

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

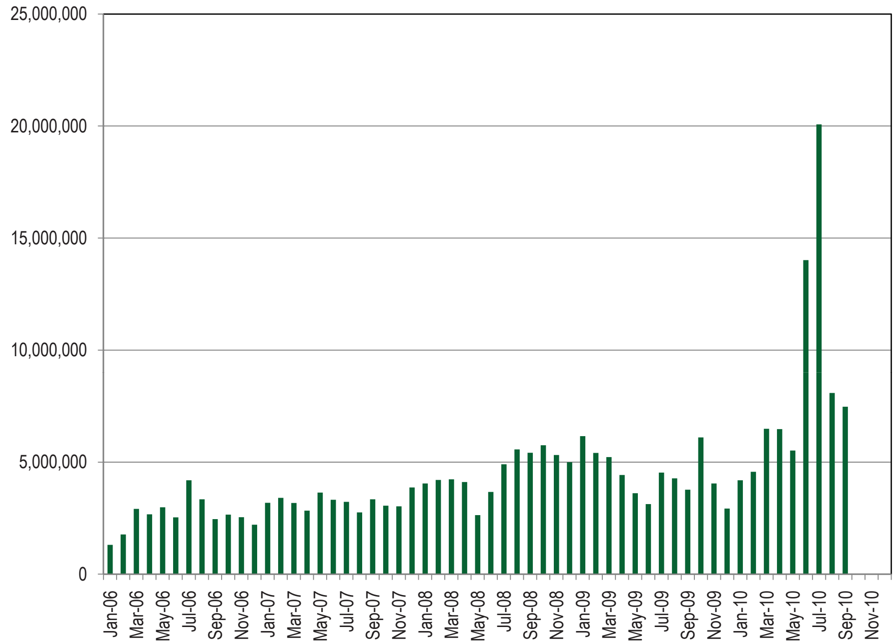


Figure 4-24 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Market transaction: January through September 2010 (See 2009 SOM, Figure 4-24)

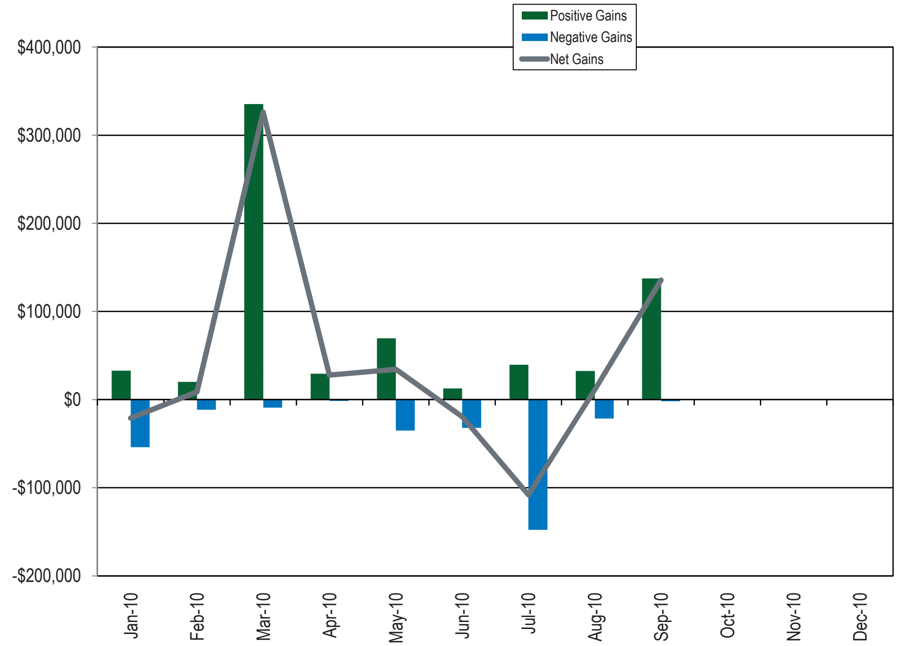


Table 4-14 Up-to congestion MW by Import, Export and Wheels: January 2006 through September 2010 (See 2009 SOM, Table 4-14)

	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	36,897,250	34,715,643	5,291,729	76,904,622	48.0%	45.1%	6.9%
TOTAL	106,923,753	139,269,979	9,664,040	255,857,773	41.8%	54.4%	3.8%

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 September 2010 (See 2009 SOM, Figure 4-25)

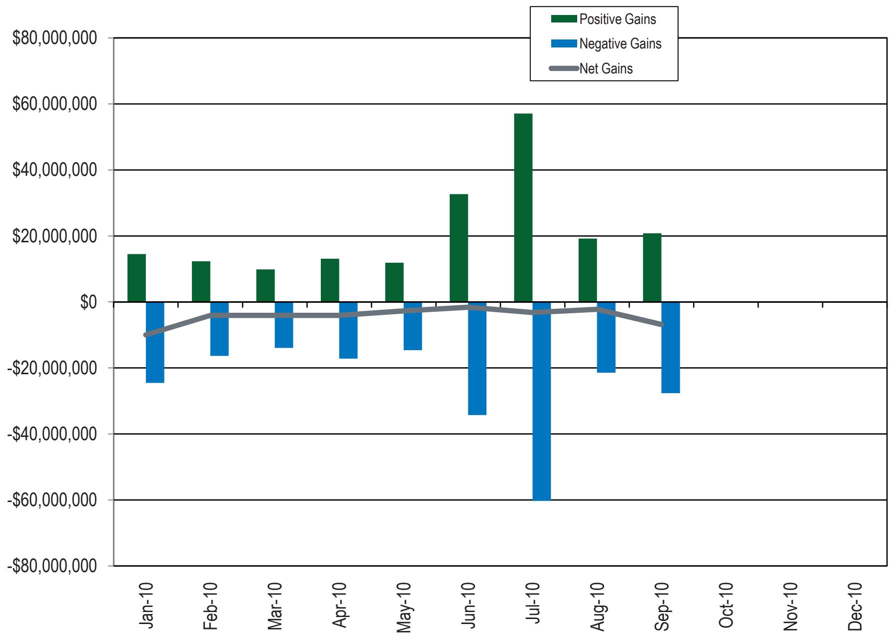


Table 4-16 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through September 2010 (See 2009 SOM, Table 4-17)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$42.03	$43.10	$40.15	$40.15	$1.88	$2.94
PEC	$42.84	$46.07	$40.15	$40.15	$2.69	$5.91
NCMPA	$42.53	$42.69	$40.15	$40.15	$2.38	$2.54

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 September 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	$44.30	$37.18	$40.15	$40.15	$4.15	($2.97)	$4.15	($2.97)

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

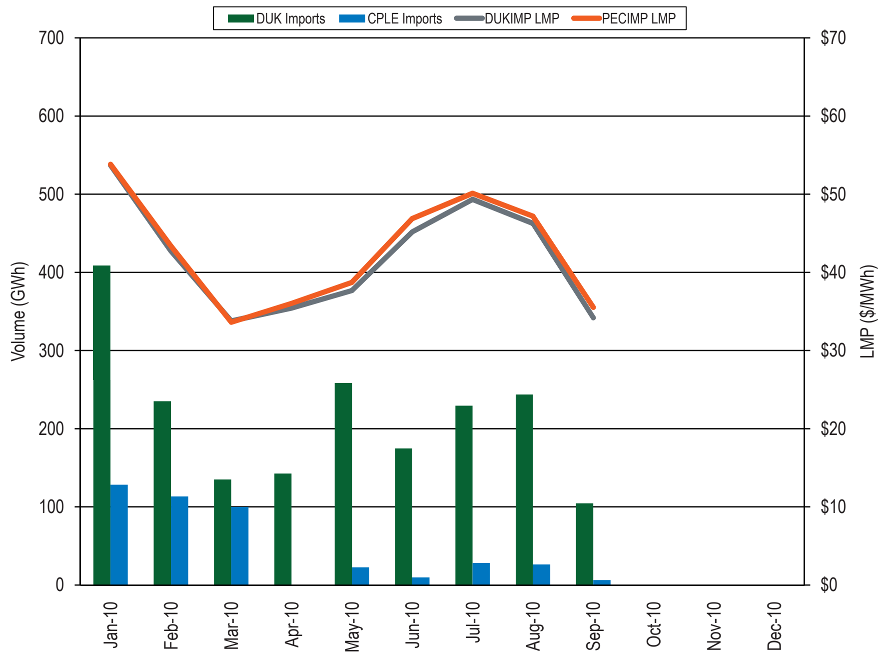


Figure 4-27 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2010 (See 2009 SOM, Figure 4-27)

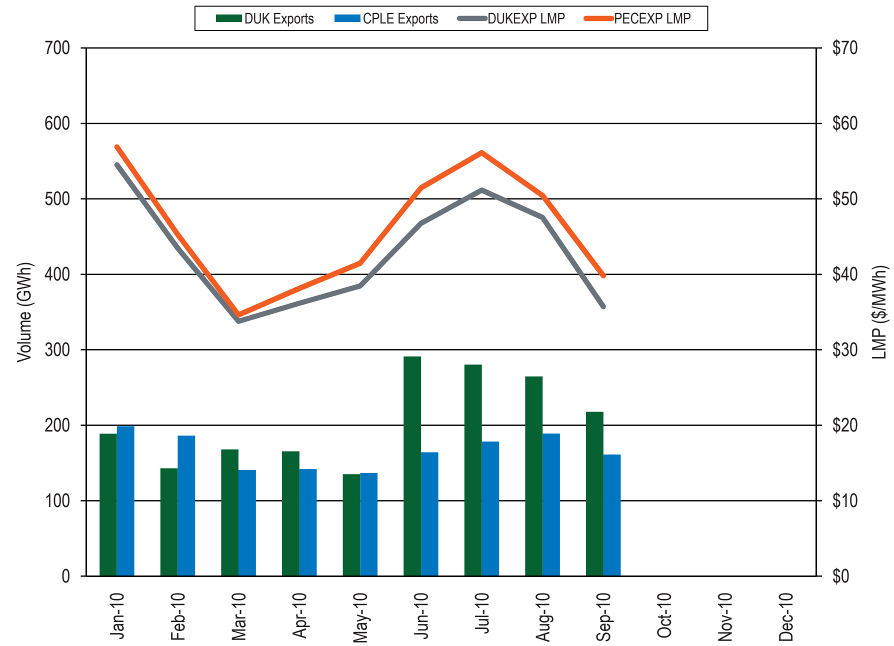


Table 4-17 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through September 2010 (New Table)

	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	$41.53	$38.10	$38.32	$41.23	$3.21	($0.22)	$0.31	($3.13)
2007	$53.50	$45.01	$48.45	$47.76	$5.06	($3.44)	$5.75	($2.75)
2008	$63.44	$52.27	$56.26	$56.26	$7.17	($3.99)	$7.17	($3.99)
2009	$36.42	$32.05	$33.59	$33.59	$2.83	($1.54)	$2.83	($1.54)
2010	$45.33	$37.57	$40.24	$40.24	$5.23	($2.73)	$5.23	($2.73)

Table 4-18 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through September 2010 (See 2009 SOM, Table 4-19)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$42.37	$43.85	$40.24	$40.24	$2.14	$3.61
PEC	$43.57	$46.61	$40.24	$40.24	$3.33	$6.37
NCMPA	$43.17	$43.31	$40.24	$40.24	$2.93	$3.07

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

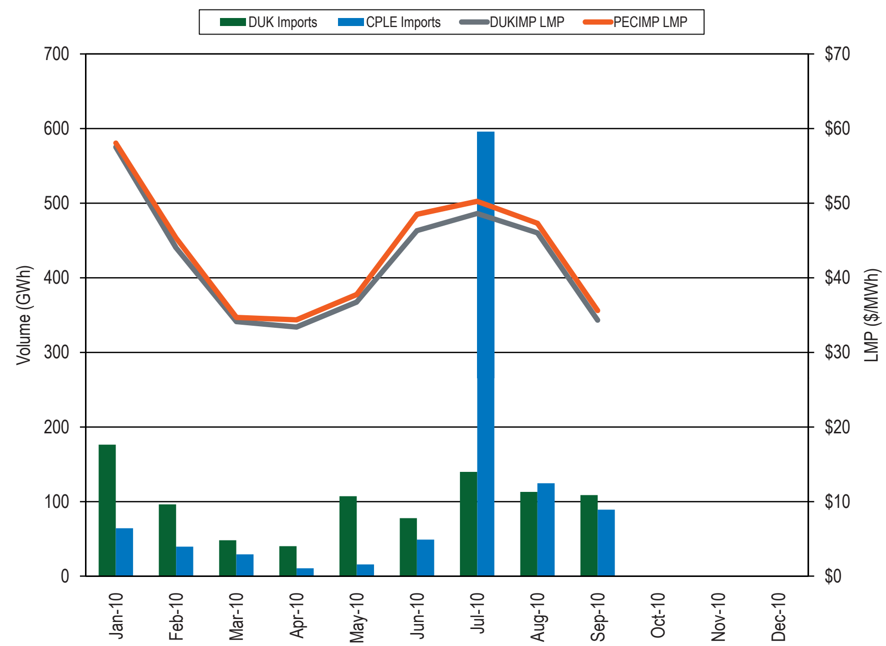
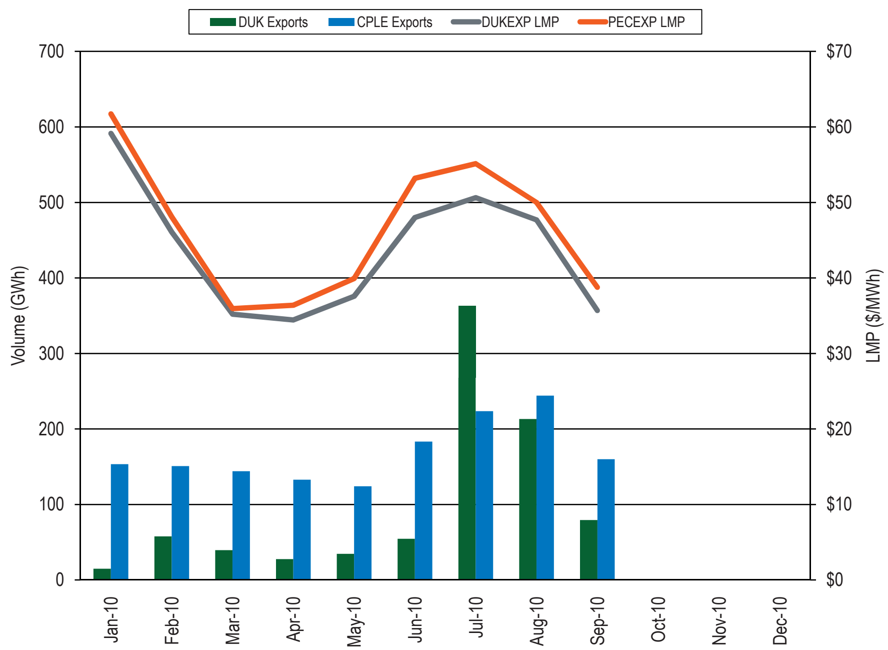
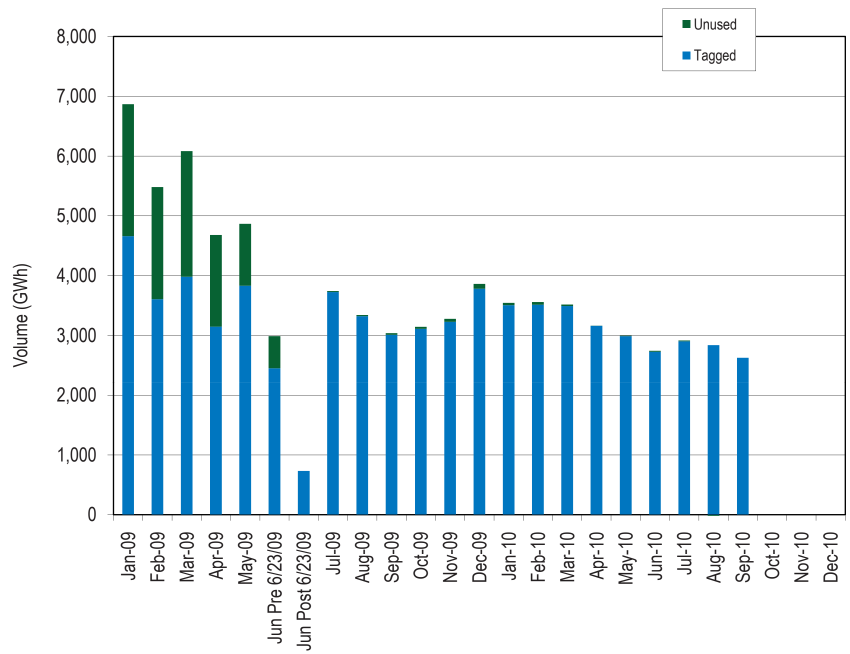


Figure 4-29 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2010 (See 2009 SOM, Figure 4-29)



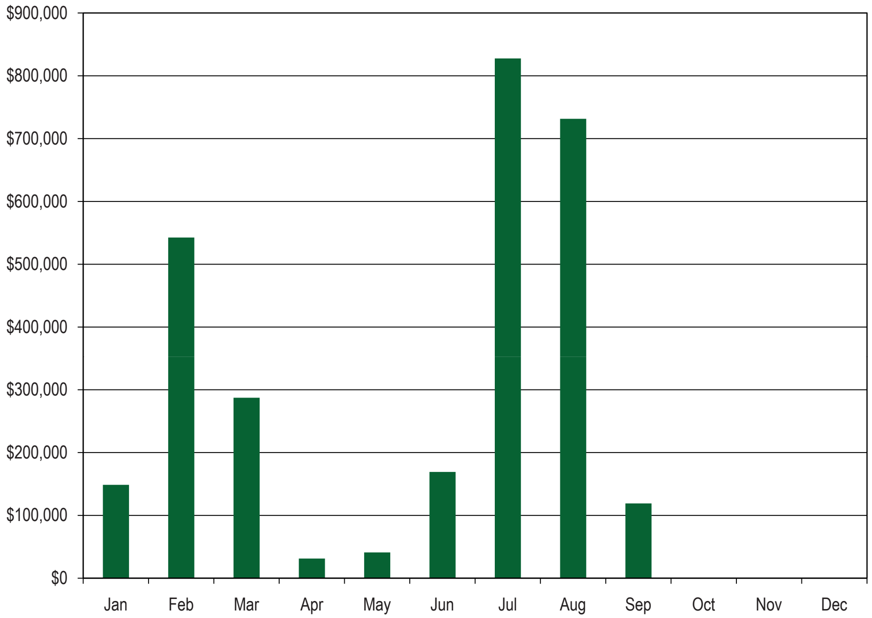
Spot Import

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



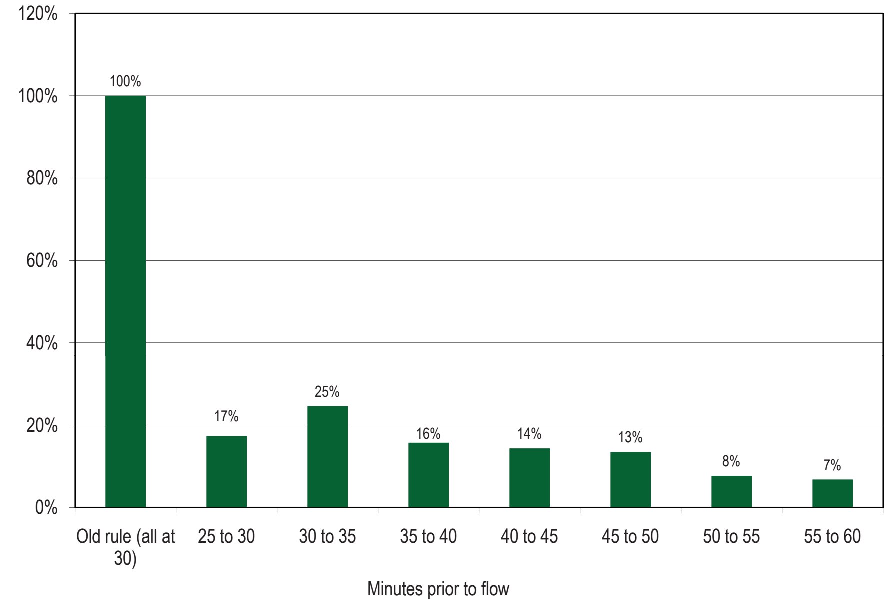
Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-31 Monthly uncollected congestion charges: January through September 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 September 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 nine 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 September*, 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 unforced capacity (UCAP).

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

In the 2011/2012, 2012/2013, and 2013/2014 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, 2012/2013 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 TPS 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.

- **RPM Net Excess.** RPM 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 value.

- **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 value.

- **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 value.

- **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 value.

- **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 value.

- **2012/2013 RPM First Incremental Auction.** Of the 162 generating resources which submitted offers, unit-specific offer caps were calculated for 14 resources (8.6 percent). Offer caps of all kinds were calculated for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR value.

- **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 value.

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

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 Revised and Updated" (September 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.

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 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 $960.4 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.

- **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 7.4 percent in the first nine months of 2009 to 6.8 percent in the first nine months of 2010. PJM EFORp increased from 4.1 percent in the first nine months of 2009 to 5.0 percent in the first nine months of 2010.[11]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 86.6 percent in the first nine months of 2009 to 86.1 percent in the first nine 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

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).

11 2009 data is for the nine months ended September 30, 2009, as downloaded from the PJM GADS database on October 21, 2010. 2010 data is for the period ending September 30, 2010, as downloaded from the PJM GADS database on October 21, 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.

are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market during the first nine 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 nine 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.[12,13,14,15,16,17]

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 Revised and Updated" (September 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.

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

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

RPM Capacity Market

Market Structure

Supply

Table 5-1 Internal capacity: June 1, 2009, to June 1, 2013[18]

	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

18 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: 2010/2011 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[19] (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
2012/2013 First IA			
RTO	0.60	25	25
EMAAC	0.00	2	2
2013/2014 BRA			
RTO	0.59	87	87
MAAC/SWMAAC	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.00	2	2
Pepco	0.00	1	1

19 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[20] (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

20 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[21,22] (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	7,524.6		4,897.4	1,807.3		66.1	72.2	
EE cleared	568.9		179.9	20.0		0.0	0.9	
RPM load management @ 01-June-2012	8,093.5		5,077.3	1,827.3		66.1	73.1	
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

21 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.

22 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 through 2011/2012 RPM Auctions (See 2009 SOM, Table 5-7)

	2010/2011 BRA		2010/2011 Third IA		2011/2012 BRA		2011/2012 First IA	
Calculation Type	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	370	33.5%	7	2.3%	299	26.6%	44	34.1%
ACR data input (APIR)	134	12.1%	1	0.3%	133	11.8%	18	14.0%
ACR data input (non-APIR)	20	1.8%	0	0.0%	12	1.1%	1	0.8%
Opportunity cost input	8	0.7%	1	0.3%	24	2.1%	2	1.6%
Default ACR and opportunity cost input	0	0.0%	0	0.0%	2	0.2%	3	2.3%
Generation resources with offer caps	532	48.1%	9	2.9%	470	41.8%	68	52.8%
Uncapped planned generation resources	15	1.4%	0	0.0%	20	1.8%	1	0.8%
Generators with 1.1 times BRA clearing price offer cap	NA		193	63.7%	NA		NA	
Generation price takers	557	50.5%	101	33.4%	635	56.4%	60	46.4%
Generation resources offered	1,104	100.0%	303	100.0%	1,125	100.0%	129	100.0%
Demand resources offered	23		34		37		0	
Energy efficiency resources offered	0		0		0		0	
Total capacity resources offered	1,127		337		1,162		129	

Table 5-8 ACR statistics: 2012/2013 through 2013/2014 RPM Auctions[23] (See 2009 SOM, Table 5-8)

	2012/2013 BRA		2012/2013 First IA		2013/2014 BRA	
Calculation Type	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	465	41.0%	92	56.8%	580	49.6%
ACR data input (APIR)	118	10.4%	14	8.6%	92	7.9%
ACR data input (non-APIR)	2	0.2%	0	0.0%	15	1.3%
Opportunity cost input	8	0.7%	2	1.2%	6	0.5%
Default ACR and opportunity cost input	14	1.2%	0	0.0%	7	0.6%
Generation resources with offer caps	607	53.5%	108	66.6%	700	59.9%
Uncapped planned generation resources	11	1.0%	17	10.5%	20	1.7%
Generators with 1.1 times BRA clearing price offer cap	NA		NA		NA	
Generation price takers	515	45.5%	37	22.9%	450	38.4%
Generation resources offered	1,133	100.0%	162	100.0%	1,170	100.0%
Demand resources offered	233		77		426	
Energy efficiency resources offered	53		3		128	
Total capacity resources offered	1,419		242		1,724	

23 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[24,25,26,27] (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

24 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.
25 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.
26 For reasons of confidentiality, the APIR statistics do not include opportunity cost based offer cap data.
27 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 APIR statistics: 2010/2011 through 2013/2014 RPM Auctions (See 2009 SOM, Table 5-9) [continued]

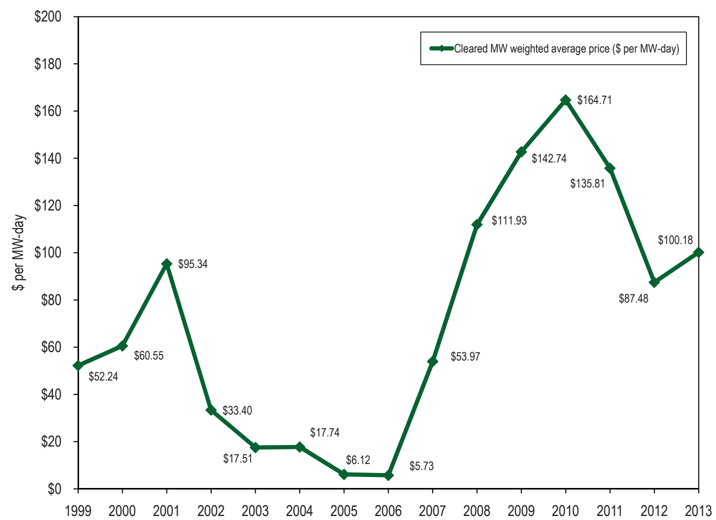
		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2012/2013 BRA							
Non-APIR units	ACR	$41.84	$32.61	$75.47	$207.54	$57.18	$110.84
	Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96	$208.65
	Offer caps	$5.28	$14.40	$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
2012/2013 First IA							
Non-APIR units	ACR	$69.71	$30.49	$86.40	$229.86	$32.75	$67.26
	Net revenues	$136.19	$5.75	$12.73	$156.50	$33.52	$30.71
	Offer caps	$32.88	$24.75	$73.67	$75.99	$27.72	$37.81
APIR units	ACR	NA	$50.56	$289.38	$660.56	NA	$367.75
	Net revenues	NA	$9.15	$50.16	$434.48	NA	$138.16
	Offer caps	NA	$41.40	$239.21	$226.09	NA	$229.59
	APIR	NA	$7.70	$156.87	$459.80	NA	$222.35
	Maximum APIR effect						$549.57
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	Pepco
2007/2008 BRA	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54
2008/2009 BRA	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11
2008/2009 Third IA	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$223.85
2009/2010 BRA	$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$237.33
2009/2010 Third IA	$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00
2010/2011 BRA	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29
2010/2011 Third IA	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
2011/2012 BRA	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00
2011/2012 First IA	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00
2011/2012 ATSI FRR Integration Auction	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2012/2013 BRA	$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37
2012/2013 ATSI FRR Integration Auction	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First IA	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46
2013/2014 BRA	$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14

Figure 5-1 History of capacity prices: Calendar year 1999 through 2013[28] (See 2009 SOM, Figure 5-1)



28 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[29,30,31] (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

29 The annual charges are calculated using the rounded, net load prices as posted by PJM.

30 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.

31 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

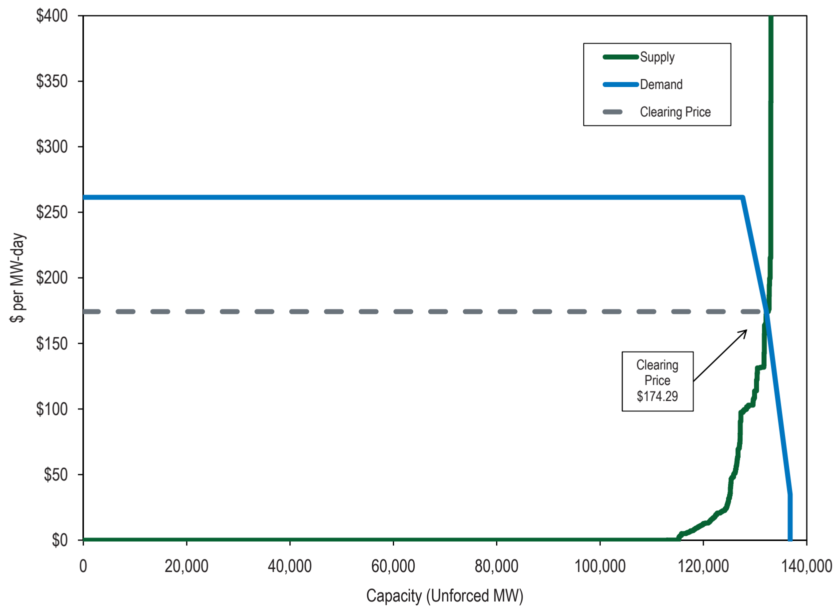
RTO

Table 5-12 RTO offer statistics: 2010/2011 RPM Base Residual Auction[32] (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	

32 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[33] (See Analysis of the 2010/2011 RPM Auction Revised)



33 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[34] (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	

34 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

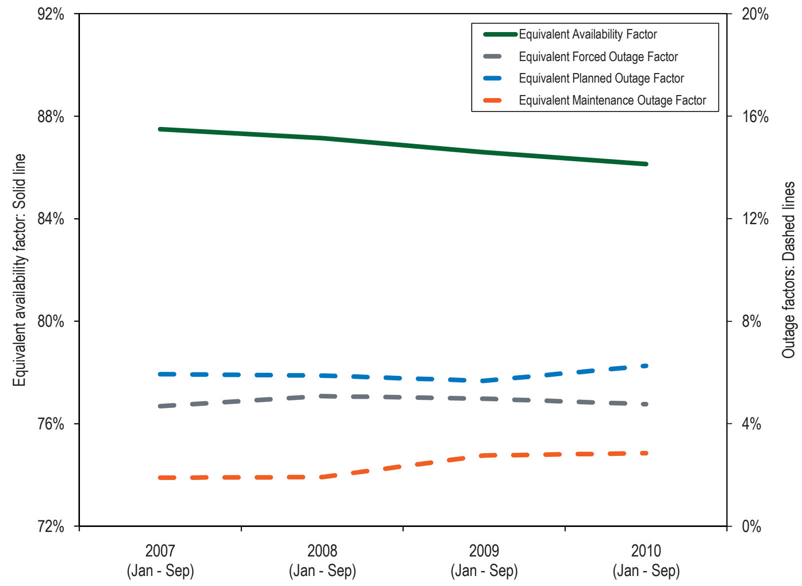
Table 5-14 RTO offer statistics: 2010/2011 RPM Third Incremental Auction (New table)

	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

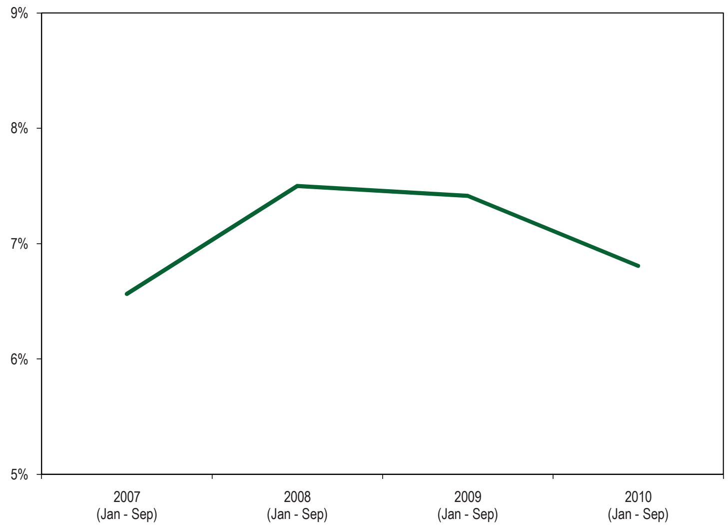
Generator Performance Factors

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



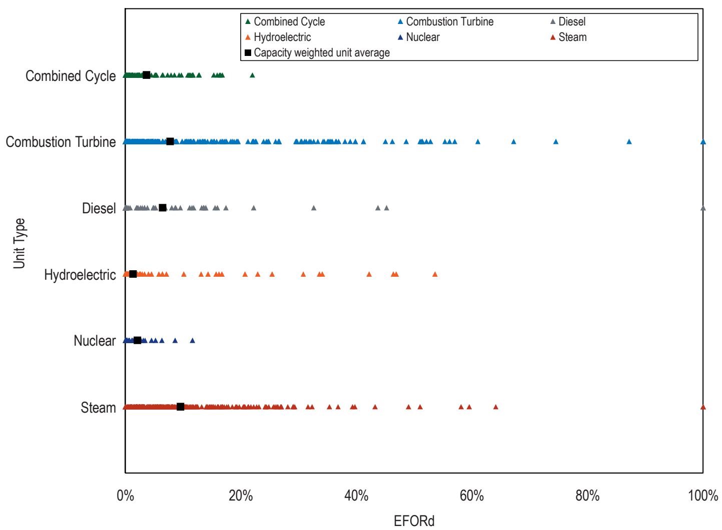
Generator Forced Outage Rates

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



Distribution of EFORd

Figure 5-5 PJM 2010 (January through September) 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 September) (See 2009 SOM, Table 5-17)

	2007 (Jan - Sep)	2008 (Jan - Sep)	2009 (Jan - Sep)	2010 (Jan - Sep)
Combined Cycle	3.3%	3.5%	4.5%	3.7%
Combustion Turbine	10.6%	10.5%	8.3%	7.8%
Diesel	13.4%	11.7%	9.3%	6.5%
Hydroelectric	2.0%	2.5%	2.7%	1.3%
Nuclear	1.2%	1.0%	4.3%	2.1%
Steam	8.6%	10.4%	9.4%	9.5%
Total	6.6%	7.5%	7.4%	6.8%

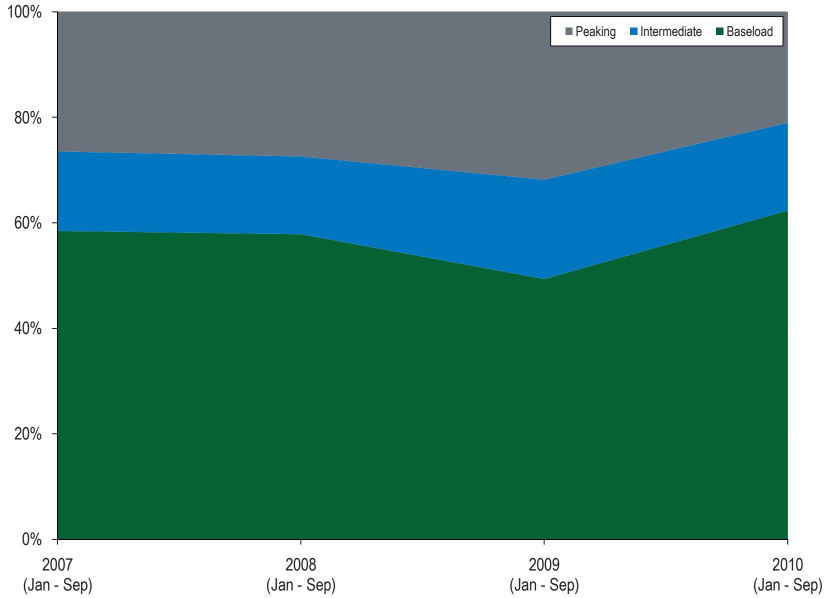
Table 5-16 Contribution to EFORd for specific unit types (Percentage points): 2007 to 2010 (January through September)[35] (See 2009 SOM, Table 5-18)

	2007 (Jan - Sep)	2008 (Jan - Sep)	2009 (Jan - Sep)	2010 (Jan - Sep)
Combined Cycle	0.4	0.4	0.5	0.4
Combustion Turbine	1.6	1.6	1.3	1.2
Diesel	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.1
Nuclear	0.2	0.2	0.8	0.4
Steam	4.2	5.2	4.7	4.7
Total	6.6	7.5	7.4	6.8

35 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 September) (See 2009 SOM, Figure 5-10)



Forced Outage Analysis

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

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	1.15	23.2%
Economic	0.46	9.2%
Electrical	0.29	5.9%
Boiler Air and Gas Systems	0.29	5.8%
Boiler Internals and Structures	0.25	5.0%
Boiler Fuel Supply from Bunkers to Boiler	0.19	3.7%
Circulating Water Systems	0.16	3.2%
Catastrophe	0.15	3.0%
Feedwater System	0.14	2.9%
Condensing System	0.14	2.8%
Stack Emission	0.11	2.2%
Boiler Piping System	0.10	2.1%
Fuel Quality	0.10	2.0%
Auxiliary Systems	0.09	1.7%
Controls	0.08	1.6%
Boiler Tube Fireside Slagging or Fouling	0.08	1.6%
Exciter	0.08	1.6%
Valve	0.06	1.3%
High Pressure Turbine	0.06	1.2%
All Other Causes	1.00	20.1%
Total	4.97	100.0%

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

	Contribution to Economic Reasons
Lack of Fuel (OMC)	74.0%
Other Economic Problems	20.6%
Lack of Fuel (Non-OMC)	4.4%
Lack of Water (Hydro)	0.8%
Fuel Conservation	0.2%
Ground Water or Other Water Supply Problems	0.0%
Total	100.0%

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

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	0.4%	0.0%	0.0%	0.0%	0.0%	28.7%	23.2%
Economic	0.5%	26.5%	11.4%	11.5%	0.0%	9.6%	9.2%
Electrical	11.2%	30.6%	3.3%	14.2%	13.4%	3.3%	5.9%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.1%	5.8%
Boiler Internals and Structures	0.4%	0.0%	0.0%	0.0%	0.0%	6.1%	5.0%
Boiler Fuel Supply from Bunkers to Boiler	0.0%	0.0%	0.0%	0.0%	0.0%	4.6%	3.7%
Circulating Water Systems	1.7%	0.0%	0.0%	0.0%	20.9%	1.9%	3.2%
Catastrophe	0.4%	0.8%	0.6%	8.2%	0.0%	3.5%	3.0%
Feedwater System	2.6%	0.0%	0.0%	0.0%	9.0%	2.5%	2.9%
Condensing System	1.2%	0.0%	0.0%	0.0%	12.0%	2.3%	2.8%
Stack Emission	0.0%	0.0%	0.3%	0.0%	0.0%	2.7%	2.2%
Boiler Piping System	4.4%	0.0%	0.0%	0.0%	0.0%	2.3%	2.1%
Fuel Quality	0.2%	0.0%	1.0%	0.0%	0.0%	2.5%	2.0%
Auxiliary Systems	2.4%	5.9%	0.0%	0.9%	12.4%	0.5%	1.7%
Controls	1.2%	1.1%	0.8%	3.4%	1.6%	1.7%	1.6%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.6%
Exciter	1.8%	1.3%	0.0%	3.3%	0.0%	1.7%	1.6%
Valve	3.8%	0.0%	0.0%	0.0%	0.1%	1.2%	1.3%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	1.2%
All Other Causes	67.6%	33.9%	82.6%	58.5%	30.5%	14.2%	20.1%
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 September) (See 2009 SOM, Table 5-22)

	EFOF	Contribution to EFOF
Combined Cycle	2.6%	6.3%
Combustion Turbine	1.5%	4.8%
Diesel	4.5%	0.2%
Hydroelectric	0.7%	0.7%
Nuclear	1.9%	7.1%
Steam	7.7%	80.8%
Total	4.8%	100.0%

Outages Deemed Outside Management Control

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

	2010 EFORd	2010 XEFORd	Difference
Combined Cycle	3.7%	3.6%	0.1%
Combustion Turbine	7.8%	5.8%	1.9%
Diesel	6.5%	4.4%	2.0%
Hydroelectric	1.3%	1.0%	0.3%
Nuclear	2.1%	2.1%	0.0%
Steam	9.5%	8.2%	1.4%
Total	6.8%	5.8%	1.0%

Components of EFORp

Table 5-22 Contribution to EFORp by unit type (Percentage points): 2009 to 2010 (January through September[36]) (See 2009 SOM, Table 5-24)

	2009 (Jan - Sep)	2010 (Jan - Sep)
Combined Cycle	0.4	0.3
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.1	0.0
Nuclear	0.8	0.5
Steam	2.3	3.8
Total	4.1	5.0

Table 5-23 PJM EFORp data by unit type: 2009 to 2010 (January through September[37]) (See 2009 SOM, Table 5-25)

	2009 (Jan - Sep)	2010 (Jan - Sep)
Combined Cycle	3.4%	2.8%
Combustion Turbine	2.4%	2.3%
Diesel	4.7%	3.6%
Hydroelectric	2.9%	1.1%
Nuclear	4.2%	2.9%
Steam	4.7%	7.6%
Total	4.1%	5.0%

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

EFORd, XEFORd and EFORp

Table 5-24 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2010 (January through September[38]) (See 2009 SOM, Table 5-26)

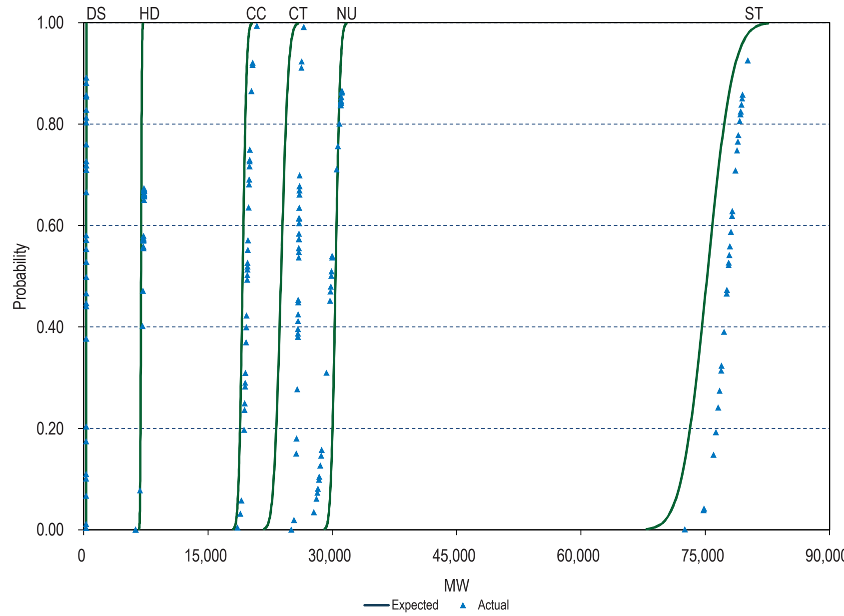
	EFORd	XEFORd	EFORp
Combined Cycle	0.4	0.4	0.3
Combustion Turbine	1.2	0.9	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.0	0.0
Nuclear	0.4	0.4	0.5
Steam	4.7	4.0	3.8
Total	6.8	5.8	5.0

Table 5-25 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2010 (January through September[39]) (See 2009 SOM, Table 5-27)

	EFORd	XEFORd	EFORp
Combined Cycle	3.7%	3.6%	2.8%
Combustion Turbine	7.8%	5.8%	2.3%
Diesel	6.5%	4.4%	3.6%
Hydroelectric	1.3%	1.0%	1.1%
Nuclear	2.1%	2.1%	2.9%
Steam	9.5%	8.2%	7.6%
Total	6.8%	5.8%	5.0%

Comparison of Expected and Actual Performance

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



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

Performance During Peak Months

Figure 5-8 PJM EFORd, XEFORd and EFORp for the peak months of January, February, June, July and August: 2010 (See 2009 SOM, Figure 5-12)

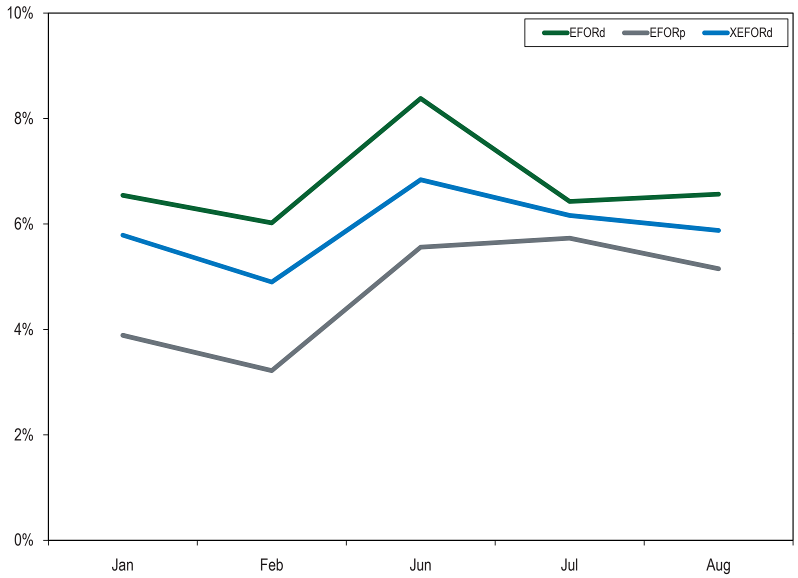
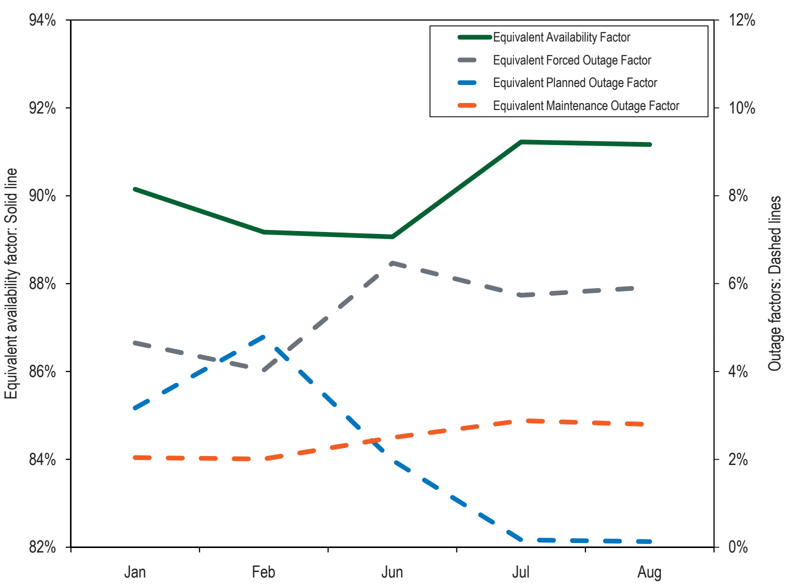


Figure 5-9 PJM peak month generator performance factors: 2010 (See 2009 SOM, Figure 5-13)



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.

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 nine 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]

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 nine months of 2010.
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 nine 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 nine months of 2010. The ratio of eligible regulation offered to regulation required averaged 2.86 for the first nine months of 2010, slightly lower than the 2009 ratio of 2.97.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements, resulting in a decrease in total demand for regulation. 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 nine months of 2010 increased to 913 MW, from 863 MW for the first nine months of 2009, as a result of increased forecast loads.

- **Market Concentration.** During the first nine months of 2010, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1401 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.[7] For the first nine months of 2010, 76 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The MMU concludes from these results that the PJM Regulation Market for the first nine months of 2010 was characterized by structural market power in 76 percent of the hours.

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). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

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

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. 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 offer cap.[8] In computing the market solution, PJM calculates a unit specific opportunity cost based on forecast LMP, and adds it to each offer. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the regulation market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. The offers of all units of owners who fail the three pivotal supplier test for an hour are capped at the lesser of their cost based or price based offer. The regulation market is then 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 was to calculate unit specific opportunity costs using the lesser of the available price based energy offer or the most expensive available cost based energy offer as the reference, rather than the offer on which the unit was operating in the energy market.[9] However, PJM did not correctly implement this rule change until the third quarter of 2010. Depending on whether the units affected by the rule change are backed down or raised to regulate determines whether the application of the rule change increased or decreased the unit's applicable opportunity costs relative to the correct original rule used prior to December 1, 2008. The impact of these changes to the calculation is that the regulation market clearing price was either higher or lower than the outcome that would have occurred under the correct opportunity cost calculation used prior to December 1, 2008. The actual impact was reduced as a result of the incorrect implementation of the rule.

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

9 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. "

Market Performance

- **Price.** For the PJM Regulation Market during the first nine 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 $19.28. This was a decrease of $4.80, or 20 percent, from the average price for regulation during the first nine months of 2009. The total cost of regulation increased by $0.35 from $33.57, for the first nine months of 2009, to $33.92, or 1 percent. The difference between total regulation cost per MW and regulation price remains high. The market clearing price was only 57 percent of the total regulation cost per MW.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market during the first nine months of 2010 were higher than they would have been in some hours and lower than they would have been in some hours as a result of the change to the definition of opportunity cost. The modified definition of opportunity cost resulted in a switch of the offer schedule used for the calculation of opportunity cost and therefore resulted in an impact on the regulation market clearing price.

  As actually implemented by PJM in 2009, the MMU calculates that schedule switching of marginal units occurred in 875 hours, of which 621 hours had higher than correct opportunity costs and 254 hours had lower than correct opportunity costs added to the marginal regulation offer.

  However, PJM did not correctly implement the rule in 2009. Had the revised opportunity cost rule been implemented as written in 2009, the schedule switching of marginal units in the regulation market would have occurred in 2,210 hours, of which 1,274 would have resulted in higher opportunity costs, and 926 would have resulted in lower opportunity costs being added to the marginal regulation offer. In the remaining 10 hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

Synchronized Reserve Market

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

PJM made two significant changes to the Synchronized Reserve Market in March 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 four percent of all synchronized reserves during the first nine months of 2010, while they were 19 percent for the same time period in 2009. Opportunity cost payments accounted for 27 percent of total costs during the first nine months of 2010 compared to 34 percent for the same time period in 2009.

Market Structure

- **Supply.** For the first nine months of 2010, synchronized reserve offers were somewhat higher than for the equivalent period in 2009. The offered and eligible excess supply ratio was 1.23 for the PJM Mid-Atlantic Synchronized Reserve Region.[10] For the RFC zone, the excess supply ratio was 2.69. 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 nine months of 2010, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

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

- **Demand.** PJM made several changes to the hourly required synchronized reserve in 2010. For the first nine months of 2010 average synchronized reserve requirements were 1,211 MW for the Mid-Atlantic Subzone. On May 5, 2010, the synchronized reserve demand in the Mid-Atlantic Subzone was increased from 1,150 MW to 1,200 MW. This change was made to accommodate a dynamically changing largest contingency for the AP South constraint. In addition, double spinning was declared for May 24 and 25 of 1,800 MW because of a planned outage. On July 17, 2010, the synchronized reserve requirement for the Mid-Atlantic Subzone was increased from 1,200 MW to 1,300 MW.

  For the first nine months of 2010, in the Mid-Atlantic Subzone no Tier 2 synchronized reserve was needed in 36 percent of hours. The average required Tier 2 (including self scheduled) was 312 MW. The average required Tier 2 fell to 207 MW for the July through September period from 365 MW during the January through June period. The decrease in Tier 2 resulted from an increase in Tier 1 during the summer months.

  For the first six months of 2010, the synchronized reserve requirement was 1,320 MW for the RFC Synchronized Reserve Zone. On July 1, 2010, the requirement for the RFC Synchronized Reserve Zone was increased from 1,320 MW to 1,350 MW. The change was made to accommodate the largest single unit contingency. Additionally, there were 85 hours between September 20 and September 29 when the synchronized reserve requirement for the RFC Synchronized Reserve Zone was increased to 1,700 MW as a result of outages. 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.

  Synchronized reserves added out of market were four percent of all synchronized reserves during January through September of 2010.

  In the PJM Mid-Atlantic Synchronized Reserve Subzone, 64 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 312 MW. The lower demand for Tier 2 from the first six months of 2010 was the result of a larger supply of Tier 1 synchronized reserve. The demand was met by self scheduled synchronized reserves, which averaged 122 MW for the first nine months, and cleared Tier 2 synchronized reserves, which averaged 190 MW for the first nine months.

  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 eight hours in the first nine months of 2010.

- **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 nine months of 2010 was 2642 which is classified as "highly concentrated."[11] For purchased synchronized reserve (cleared plus added) the HHI was 2686. During the first nine months of 2010, in 40 percent of hours the maximum market share was greater than 40 percent, compared to 41 percent of hours in the first nine months of 2009.

  In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for the first nine months of 2010, 36 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in the first nine months of 2010, were 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 nine months of 2010. In nine 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.

11 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).

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 $11.51 per MW for the first nine months of 2010, a $3.76 per MW increase from 2009. The market clearing price was only 70 percent of the total synchronized reserve cost per MW, lower than 2010. The difference between price and cost narrowed during 2009 as a result of several efforts by PJM to have the Synchronized Reserve Market more closely satisfy the needs of PJM dispatch.[12] As of September 2010, the price/cost ratio of synchronized reserve appears to be returning to its pre-2009 value of approximately 70 percent.

- **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 nine months of 2010.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[13] 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.[14] 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 nine months of 2010 less than two percent of hours failed the three pivotal supplier test in the DASR Market.

- **Demand.** Since January 2010, the required DASR is 6.88 percent of peak load forecast, up from 6.75 percent in 2009. [15] As a result of increased demand for energy, reflected in higher forecast peak loads and increased DASR requirements, the DASR MW purchased increased by 15 percent in the first nine months of 2010 over the same period in 2009.

12 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary service Markets," at "Price and Cost", p. 392.
13 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
14 PJM. "Manual 13: Emergency Operations," Revision 40, (August 13, 2010); pp 11-12.
15 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*, p. 397.

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 $0.18 and a maximum clearing price of $39.99.

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

Market Performance

- **Price.** For the first nine months of 2010, the load weighted average price of DASR was $0.18, a significant increase over the average prices from January through June of $0.06 (See Table 6-14). DASR prices have been higher throughout 2010, and significantly higher in the third quarter.

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.[16]

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

16 PJM OATT Schedule § 1.3BB, Second Revised Sheet No. 33.01, March 1, 2007.

service, as defined in the tariff. For 2009, charges were about $12.3 million. For the first nine months of 2010 charges were $7.3 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.[17] The MMU's conclusion regarding the results of the Regulation Market are not the result of the behavior of market participants, which was competitive, in part as a result of the application of the three pivotal supplier test, but are the result of the market design changes. 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, are inconsistent with basic economic logic, and because of incorrect implementation of the market rules. For example, 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, resulted in offers less than competitive offers in some hours and therefore in prices less than competitive prices in some hours.[18] 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 MMU recommends that the December 1, 2008, 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 MMU also recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected. This change would maintain transparent incentives consistent with an effective market design. In the longer run, the proposed modifications to the pricing of regulation by both PJM and the MMU in their scarcity pricing recommendations will result in revenue increases that are expected to exceed any revenue loss from correcting the opportunity cost calculation.19 The MMU recommends that when the scarcity related modifications are implemented, the margin be reduced to its current level.

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 nine 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.

17 See the *2009 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets."

18 The MMU has determined that the MMU's 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. A complete quantification of the impact is not required as a precondition to modifying the flawed market design. Differences from PJM estimates were the result of incorrect calculations by the MMU, which accounted for much of the difference, but were also the result of incorrect implementation of the rules by PJM.

Overall, the MMU concludes that the Regulation Market results were not competitive in the first nine months of 2010 as a result of the identified market design changes and their implementation, and not participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in the first nine months of 2010. The MMU concludes that the DASR Market results were competitive in the first nine months of 2010.

Regulation Market

Market Structure

Supply and Demand

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

Month	Average Required Regulation (MW)	Ratio of Eligible Supply to Requirement
Jan	948	2.78
Feb	942	2.88
Mar	800	2.64
Apr	724	2.86
May	800	2.9
Jun	1,005	2.91
Jul	1,094	2.83
Aug	1,040	2.91
Sep	862	3.04

Table 6-2 PJM regulation capability, daily offer[19] and hourly eligible: January through September 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	7,863	5,594	71%	2,583	33%
Off Peak	7,863			2,307	29%
On Peak	7,863			2,888	37%

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

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

Market Concentration

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

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, January - September, 2010	763	1401	2983

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

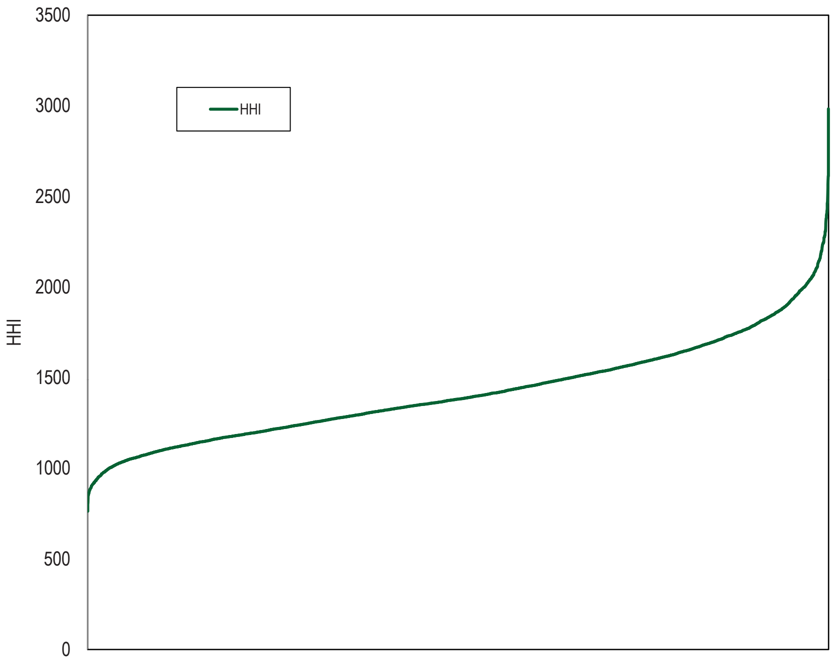


Table 6-4 Highest annual average hourly Regulation Market shares: January through September 2010 (See 2009 SOM, Table 6-4)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	17%
2	15%
3	15%
4	14%
5	9%

Table 6-5 Regulation market monthly three pivotal supplier results: January through September 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%
Jul	75%
Aug	69%
Sep	70%

Table 6-6 Percent of hours when marginal unit supplier failed PJM's three pivotal supplier test: January through September 2010 (See 2009 SOM, Table 6-6)

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	67%
Feb	58%
Mar	71%
Apr	81%
May	78%
Jun	76%
Jul	69%
Aug	60%
Sep	57%

Market Performance

Price

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): January through September 2010 (See 2009 SOM, Figure 6-3)

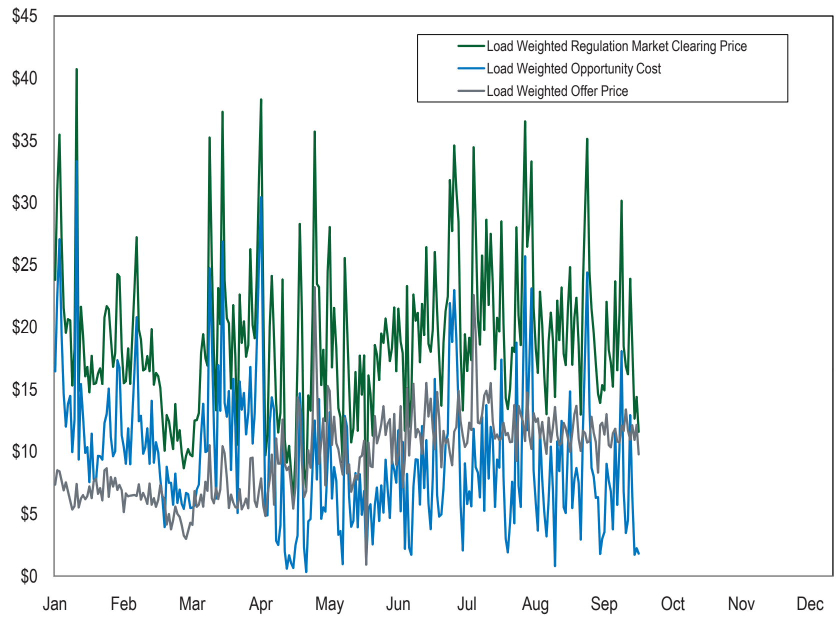


Figure 6-4 Monthly average regulation demand (required) vs. price: January through September 2010 (See 2009 SOM, Figure 6-4)

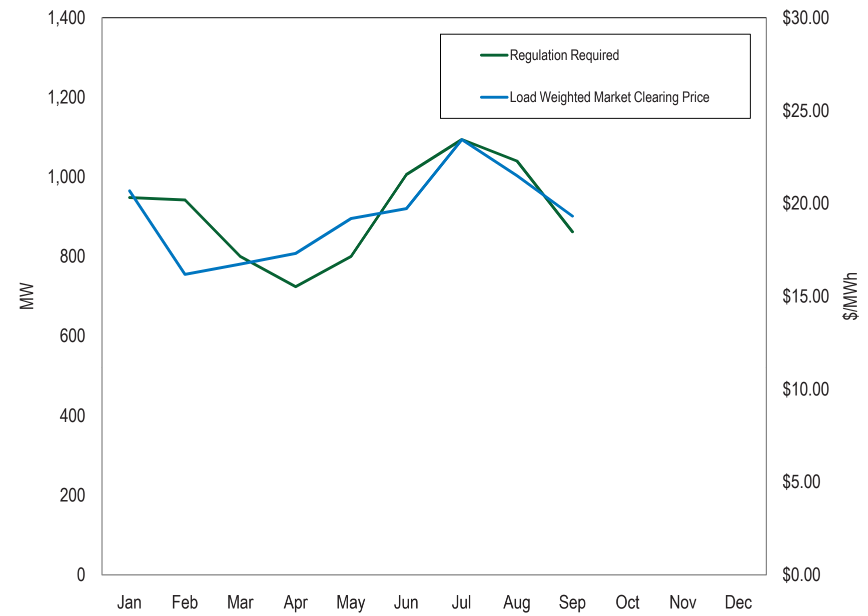


Figure 6-5 Monthly load weighted, average regulation cost and price: January through September 2010 (See 2009 SOM, Figure 6-5)

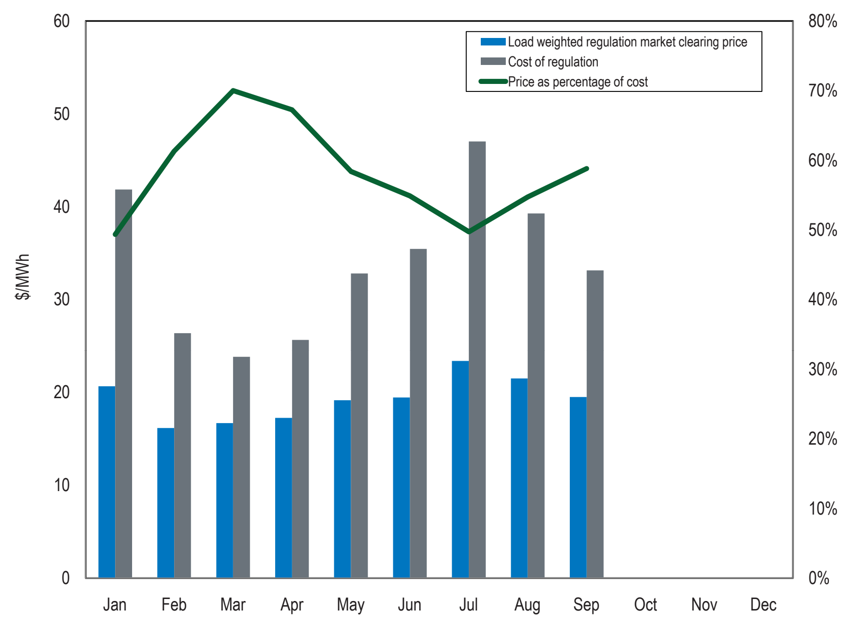


Table 6-7 Total regulation charges: January through September 2010 (See 2009 SOM, Table 6-7)

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	594,378	$14,167,033	$16.69	$23.84
Apr	518,526	$13,307,387	$17.26	$25.66
May	588,452	$19,307,043	$19.16	$32.81
Jun	658,837	$23,355,270	$19.46	$35.45
Jul	723,322	$34,017,913	$23.39	$47.03
Aug	750,524	$29,482,419	$21.50	$39.28
Sep	580,410	$19,238,702	$19.27	$32.98

Table 6-8 Comparison of load weighted price and cost for PJM Regulation, August 2005 through September 2010[20] (New Table)

Year	Load Weighted Regulation Market Price	Load Weighted Regulation Market Cost	Regulation Price as Percent Cost
2005	$64.03	$77.39	83%
2006	$32.69	$44.98	73%
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010 (Jan-Sep)	$19.28	$33.92	57%

Regulation Market Changes

Table 6-9 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.

20 The PJM Regulation Market in its current structure began August 1, 2005. See the *2005 State of the Market Report for PJM*, "Ancillary Service Markets." pp. 249-250.

TPS Testing

Table 6-10 Regulation Market pivotal supplier test results: December 2008 through September 2010 and December 2007 through September 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%
2010	Jul	75%	2009	Jul	39%
2010	Aug	69%	2009	Aug	35%
2010	Sep	70%	2009	Sep	47%

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 September 2010 (See 2009 SOM, Figure 6-6)

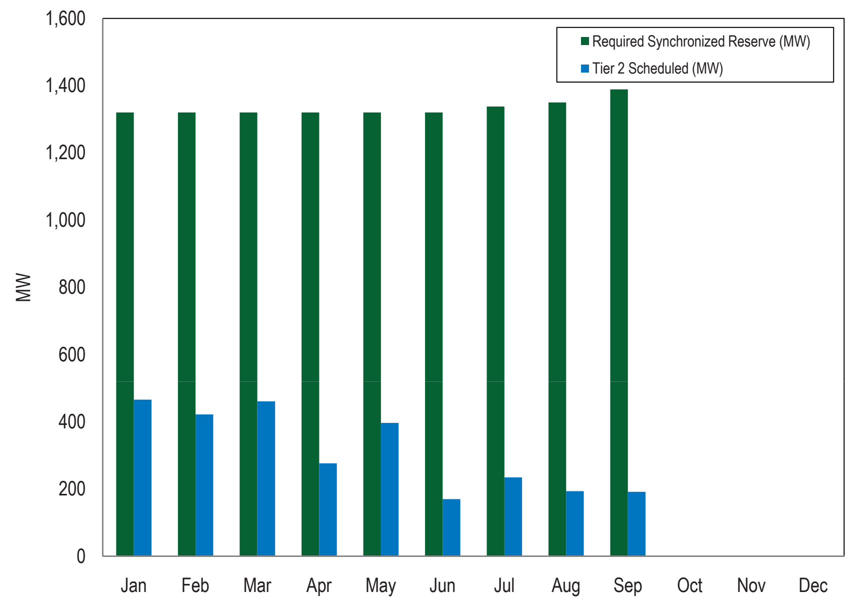
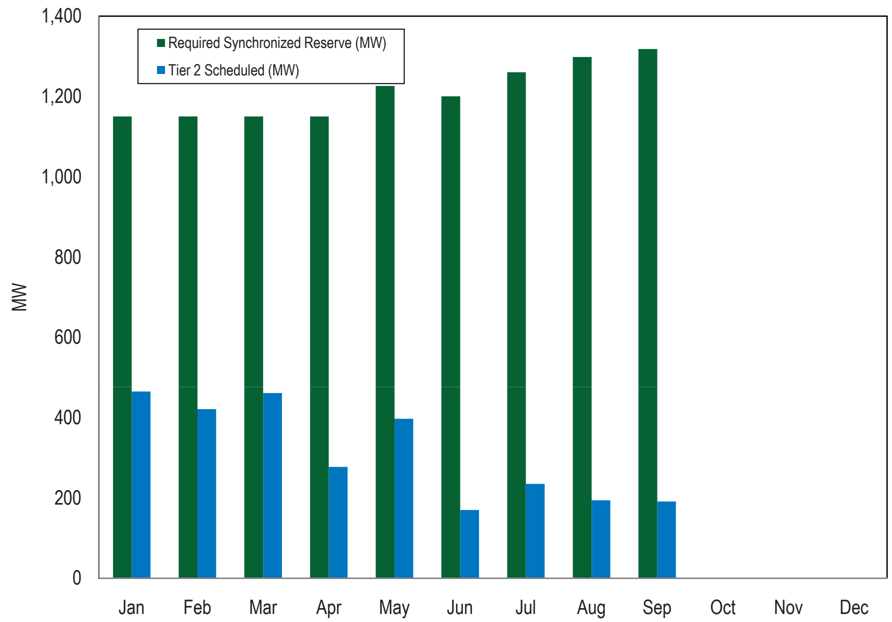


Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through September 2010 (See 2009 SOM, Figure 6-7)



Market Concentration

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

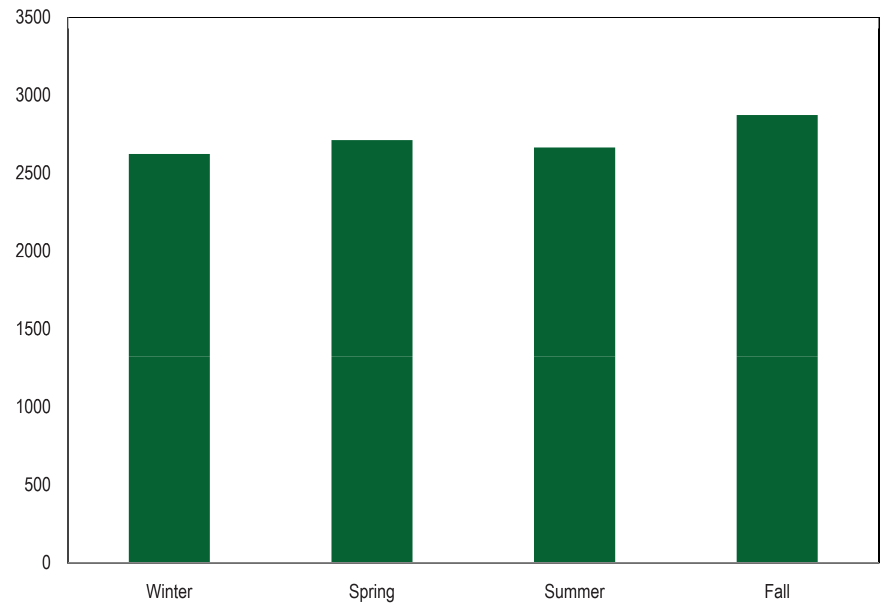


Table 6-11 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: January through September 2010 (See 2009 SOM, Table 6-15)

Company Market Share Rank	Cleared Synchronized Reserve Top Market Shares
1	32%
2	27%
3	24%
4	20%
5	18%

Market Conduct

Offers

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

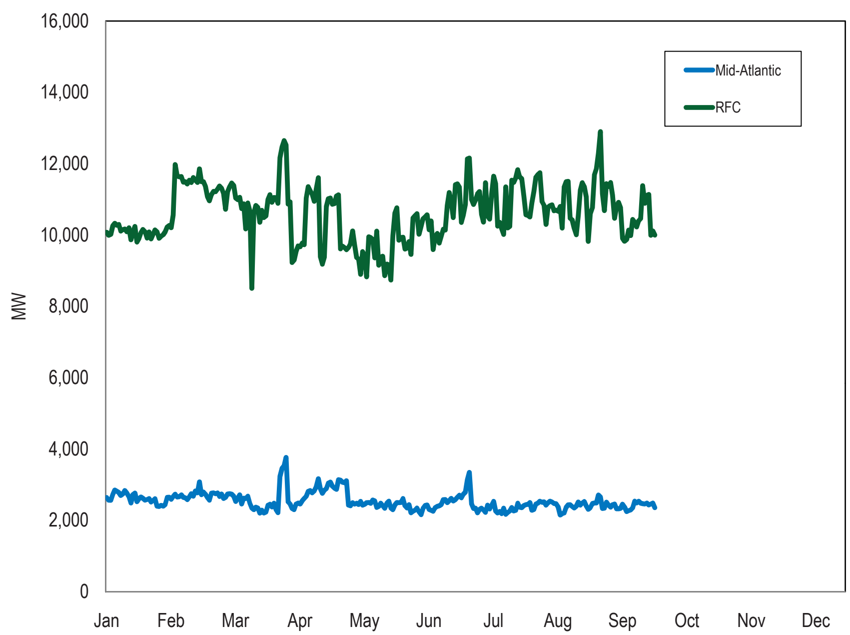
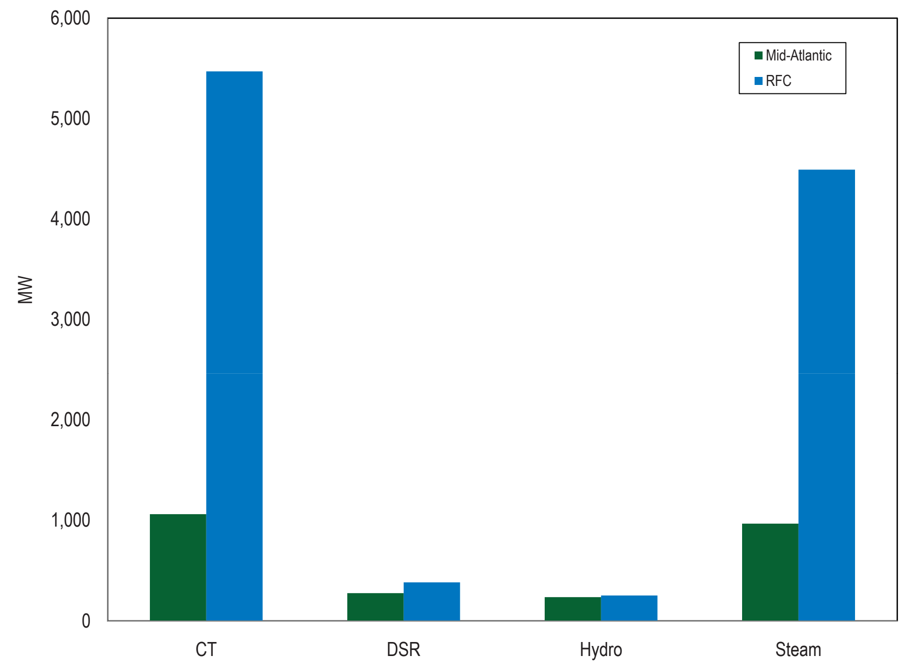


Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through September 2010 (See 2009 SOM, Figure 6-10)

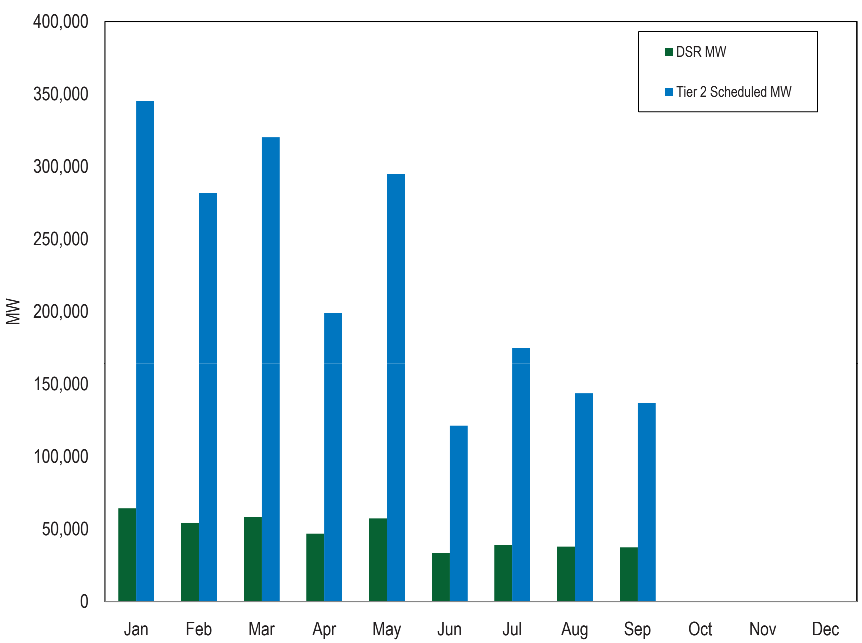


DSR

Table 6-12 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 September 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%
Jul	$16.30	28%	$0.79	7%
Aug	$11.17	34%	$0.93	12%
Sep	$10.45	33%	$1.15	12%

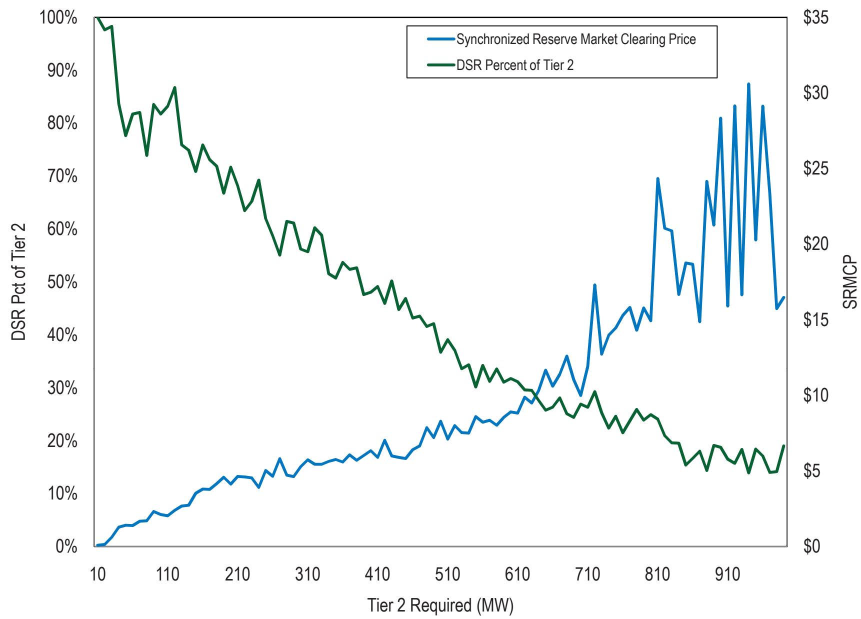
Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through September 2010 (See 2009 SOM, Figure 6-11)



Market Performance

Price

Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: January through September 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 September 2010 (See 2009 SOM, Figure 6-13)

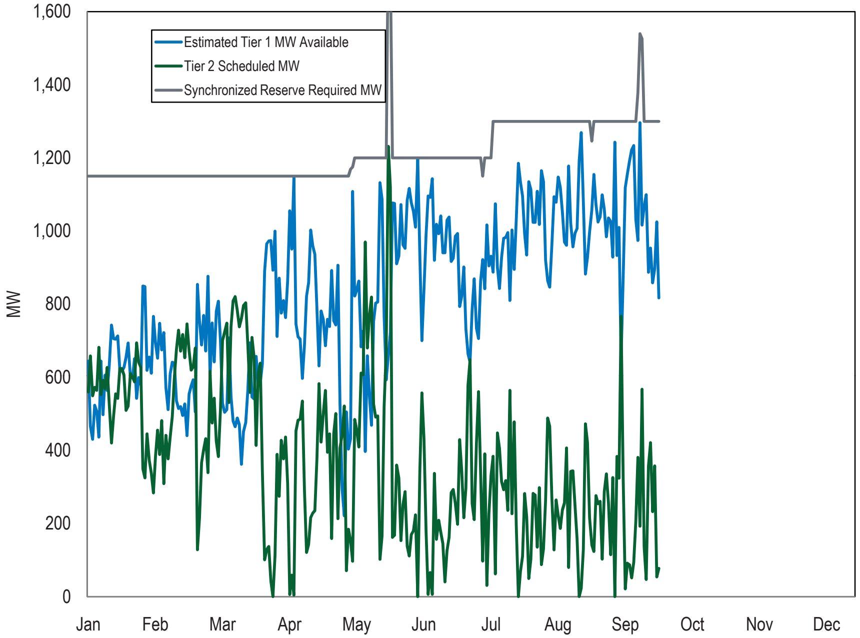


Figure 6-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through September 2010 (See 2009 SOM, Figure 6-14)

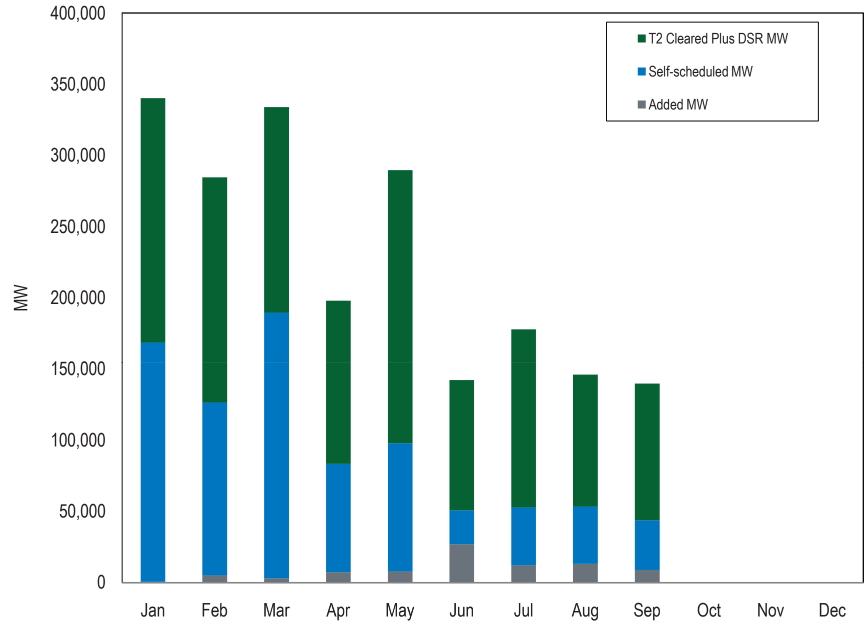


Figure 6-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through September 2010 (See 2009 SOM, Figure 6-15)

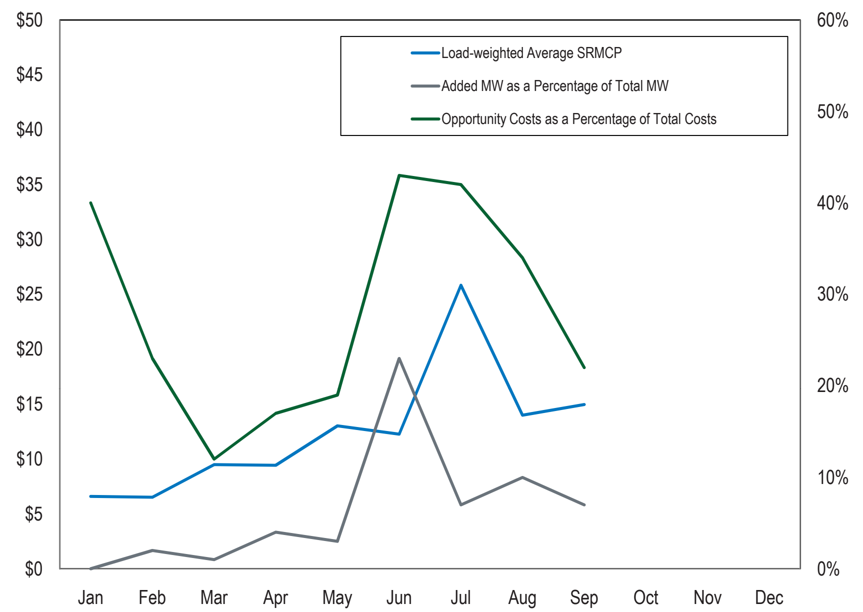


Figure 6-16 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): January through September 2010 (See 2009 SOM, Figure 6-16)

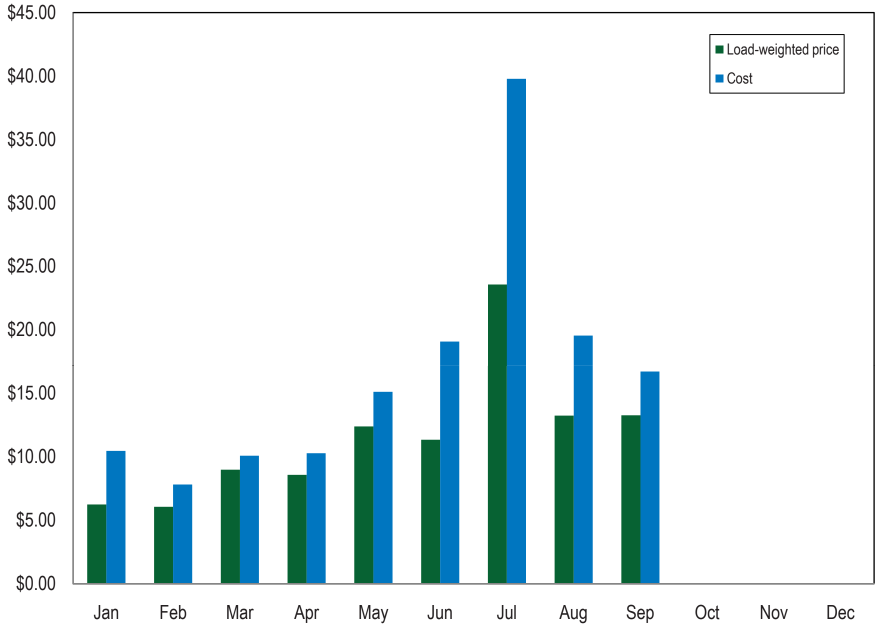


Table 6-13 Comparison of load weighted price and cost for PJM Synchronized Reserve, January 2005 through September 2010 (New Table)

Year	Load Weighted Synchronized Reserve Market Price	Load Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$13.29	$17.59	76%
2006	$14.57	$21.65	67%
2007	$11.22	$16.26	69%
2008	$10.65	$16.43	65%
2009	$7.75	$9.77	79%
2010 (Jan-Sep)	$11.51	$16.54	70%

Day-Ahead Scheduling Reserve (DASR)

Table 6-14 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September 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	$838,178
Jul	7,464	$0.00	$39.99	$0.76	5,553,319	$3,606,940
Aug	7,131	$0.00	$12.00	$0.38	5,305,750	$1,754,295
Sep	5,889	$0.00	$5.00	$0.06	4,239,965	$241,798

Black Start Service

Table 6-15 Black Start yearly zonal charges for network transmission use: January through September 2010 (See 2009 SOM, Table 6-18)

Zone	Network Charges
AECO	$274,395
AEP	$481,242
AP	$99,639
BGE	$362,682
ComEd	$2,753,344
DAY	$102,563
DLCO	$20,730
DPL	$269,639
JCPL	$324,274
Met-Ed	$301,423
PECO	$561,358
PENELEC	$245,883
Pepco	$178,292
PPL	$111,807
PSEG	$1,089,557
UGI	$111,807

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 nine 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 $598.0 million or 110 percent, from $543.6 million in the first nine months of 2009 to $1,141.6 million in the first nine months of 2010. Day-ahead congestion costs increased by $600.4 million or 85 percent, from $704.6 million in the first nine months of 2009 to $1,305 million in the first nine months of 2010. Balancing congestion costs decreased by $2.4 million or one percent, from -$161.0 million in the first nine months of 2009 to -$163.4 million in the first nine 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 nine months of 2010. Total PJM billings in the first nine months of 2010 were $26.249 billion.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In the first nine 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 nine months of 2010 ranged from $20.4 million in March to $272.5 million in July.

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 nine months of 2010.[3] Day-ahead congestion frequency increased from 2009 to 2010 by 14,436 congestion event hours or 24 percent. In the first nine months of 2010, there were 73,499 day-ahead, congestion-event hours compared to 59,063 day-ahead, congestion-event hours in the first nine months of 2009. Day-ahead, congestion-event hours increased on internal PJM interfaces and lines while congestion frequency on transformers and 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 4,601 congestion event hours. In the first nine months of 2010, there were 17,136 real-time, congestion-event hours compared to 12,535 real-time, congestion-event hours in the first nine 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 and transformers saw decreases. The AP South Interface was the largest contributor to congestion costs in the first nine months of 2010. With $342.2 million in total congestion costs, it accounted for 30 percent of the total PJM congestion costs in the first nine months of 2010. The top five constraints in terms of congestion costs together contributed $615.4 million, or 54 percent, of the total PJM congestion in the first nine months of 2010. The top five constraints were the AP South interface, the Bedington – Black Oak interface, the 5004/5005 interface, the Doubs transformer, and the AEP-DOM interface.

- **Zonal Congestion.** In the first nine months of 2010, the Dominion Control Zone experienced the highest congestion costs of the control zones in PJM with $224.7 million. The AP South interface, the Cloverdale – Lexington line, the Doubs transformer, the Bedington – Black Oak interface, and the Clover transformer contributed $150.7 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 nine months of 2010. The $226.5 million in congestion costs in the AP Control Zone represented a 225 percent increase from the $69.7 million in congestion costs the zone had experienced in the first nine months of 2009. The AP South interface contributed $86.6 million, or 38 percent of the total AP Control Zone congestion cost. Increases in day-ahead congestion frequency and congestion costs from the Doubs transformer and then Bedington – Black Oak interface and also contributed to the increase in congestion cost in the AP Control Zone from 2009 to 2010. The Doubs transformer contributed $26.3 million to the AP Control Zone congestion costs and the Bedington – Black Oak interface contributed $25.9 million to the AP Control Zone congestion costs.

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.** The FERC's recent decisions in the *Primary Power* and *Central Transmission* cases addressed significant issues about the ownership of transmission, the resultant incentives to build new transmission facilities and the potential for competitive forces to

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.

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).

reduce the cost of transmission.[5] On June 17, 2010, the FERC issued a Notice of Proposed Rulemaking (NOPR) including a proposal to "remove from Commission-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a nonincumbent transmission developer."[6] These cases and the proposed rule have the potential to significantly change the incentives to build transmission for both incumbents and potential entrants and therefore to have potentially significant impacts on the wholesale power markets.

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 nine months of 2010. Total PJM billings in the first nine months of 2010 were $26.249 billion. Total congestion costs increased by $598.0 million or 110 percent, from $543.6 million in the first nine months of 2009 to $1,141.6 million in the first nine months of 2010. Day-ahead congestion costs increased by $600.4 million or 85 percent, from $704.6 million in the first nine months of 2009 to $1,305 million in the first nine months of 2010. Balancing congestion costs decreased by $2.4 million or one percent, from -$161.0 million in the first nine months of 2009 to -$163.4 million in the first nine months of 2010. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. Day-ahead congestion frequency increased from 2009 to 2010 by 14,436 congestion event hours or 24 percent. In the first nine months of 2010, there were 73,499 day-ahead, congestion-event hours compared to 59,063 day-ahead, congestion-event hours in the first nine months of 2009. Real-time congestion frequency increased from 2009 to 2010 by 4,601 congestion event hours. In the first nine months of 2010, there were 17,136 real-time, congestion-event hours compared to 12,535 real-time, congestion-event hours in the first nine months of 2009.

5 131 FERC ¶ 61,015 (April 13, 2010); 131 FERC ¶ 61,243 (June 17, 2010).

6 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC Docket No. RM10-23-000, Summary.

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.[7] During the first four months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 98.2 percent of the congestion costs within PJM. 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 92.1 percent of the target allocation level for the first four months 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 3.6 percent of total energy charges to load for the first nine months of 2010.

One constraint accounted for 30 percent of total congestion costs in the first nine months of 2010 and the top five constraints accounted for 54 percent of total congestion costs. The AP South Interface was the largest contributor to congestion costs in the first nine 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.[8] 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

7 See the *2010 Quarterly State of the Market Report for PJM: January through September*, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-14, "ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011."

8 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.

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).

As an example, total congestion costs in PJM in the first nine months of 2010 were $1,141.6 million, which was comprised of load congestion payments of $334.1 million, negative generation credits of $851.3 million and negative explicit congestion of $43.8 million (see Table 7-2).

Congestion

Total Calendar Year Congestion

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 through September 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 - Sep)	$1,142	NA	$26,249	4%
Total	$9,591		$176,836	5%

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through September 2009 and 2010 (See 2009 SOM, Table 7-2)

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2009 (Jan - Sep)	$210.6	($380.9)	($48.0)	$543.6
2010 (Jan - Sep)	$334.1	($851.3)	($43.8)	$1,141.6

Monthly Congestion

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2008 through September 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	$272.5
Aug	$127.4	$72.1	$106.1
Sep	$124.8	$23.9	$117.5
Oct	$102.2	$42.7	
Nov	$93.0	$36.3	
Dec	$78.4	$96.4	
Total	$2,116.6	$719.0	$1,141.6

Congestion Component of LMP

Table 7-4 Annual average congestion component of LMP: January through September 2009 and 2010 (See 2009 SOM, Table 7-4)

	2009 (Jan - Sep)		2010 (Jan - Sep)	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$2.35	$2.13	$2.96	$3.87
AEP	($2.24)	($2.32)	($4.41)	($5.23)
AP	$0.83	$1.62	($0.28)	($0.42)
BGE	$3.24	$3.05	$5.90	$6.72
ComEd	($5.61)	($6.24)	($6.63)	($7.87)
DAY	($3.01)	($2.99)	($5.01)	($5.92)
DLCO	($3.73)	($3.53)	($4.69)	($6.08)
Dominion	$2.59	$2.60	$5.13	$5.31
DPL	$2.58	$2.67	$3.20	$3.99
JCPL	$2.07	$2.11	$2.43	$2.79
Met-Ed	$2.33	$2.21	$3.41	$3.78
PECO	$2.10	$1.88	$2.73	$2.99
PENELEC	$0.01	($0.04)	($1.32)	($2.36)
Pepco	$3.78	$3.82	$6.29	$6.61
PPL	$2.12	$1.90	$2.26	$2.38
PSEG	$2.45	$2.53	$2.96	$3.59
RECO	$1.69	$1.73	$2.16	$2.04

Congested Facilities

Congestion by Facility Type and Voltage

Table 7-5 Congestion summary (By facility type): January through September 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	$0.1	($31.6)	$5.2	$36.8	($2.9)	$3.0	($21.8)	($27.7)	$9.1	4,168	1,575
Interface	$93.5	($479.3)	$4.2	$577.0	$20.3	$14.6	($2.7)	$3.0	$579.9	7,610	2,020
Line	$146.5	($306.9)	$48.5	$501.8	($23.3)	$19.5	($75.0)	($117.9)	$383.9	53,382	11,098
Transformer	$91.1	($67.1)	$5.6	$163.8	($3.4)	$4.5	($12.9)	($20.8)	$143.0	8,339	2,443
Unclassified	$12.4	($8.2)	$5.2	$25.7	$0.0	$0.0	$0.0	$0.0	$25.7	NA	NA
Total	$343.4	($892.9)	$68.6	$1,305.0	($9.3)	$41.7	($112.4)	($163.4)	$1,141.6	73,499	17,136

Table 7-6 Congestion summary (By facility type): January through September 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	$16.7	($40.9)	$15.2	$72.9	($10.8)	$3.5	($61.1)	($75.4)	($2.5)	6,119	2,656
Interface	$39.2	($193.8)	$1.3	$234.3	$3.2	($2.3)	$1.9	$7.4	$241.7	4,154	1,058
Line	$97.2	($154.3)	$35.9	$287.4	($16.2)	$8.0	($32.1)	($56.3)	$231.1	39,925	6,040
Transformer	$89.9	($2.2)	$21.8	$114.0	($11.4)	($5.2)	($30.6)	($36.8)	$77.2	8,865	2,781
Unclassified	$2.7	$6.2	($0.4)	($3.9)	$0.0	$0.0	$0.0	$0.0	($3.9)	NA	NA
Total	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$543.6	59,063	12,535

Table 7-7 Congestion summary (By facility voltage): January through September 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	$119.0	($524.1)	$11.2	$654.3	$16.9	$5.4	($17.3)	($5.8)	$648.5	9,752	3,630
345	($2.2)	($104.7)	$20.6	$123.2	($10.4)	$8.7	($59.4)	($78.6)	$44.6	9,169	2,922
230	$76.7	($145.3)	$18.5	$240.6	$2.0	$19.0	($18.8)	($35.8)	$204.8	15,177	3,187
138	$92.8	($106.0)	$12.0	$210.8	($11.8)	$3.9	($12.8)	($28.5)	$182.4	28,573	5,536
115	$30.6	($5.9)	$0.5	$37.0	$0.3	$3.8	($0.6)	($4.1)	$32.9	4,901	1,189
69	$13.3	$3.0	$0.2	$10.5	($5.4)	$0.8	($0.3)	($6.6)	$4.0	5,568	579
34	($0.0)	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	37	19
12	$0.3	$0.2	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	245	0
Unclassified	$12.4	($8.2)	$5.2	$25.7	($0.0)	($0.0)	($0.0)	$0.0	$25.7	NA	NA
Total	$343.4	($892.9)	$68.6	$1,305.0	($9.3)	$41.7	($112.4)	($163.4)	$1,141.6	73,499	17,136

Table 7-8 Congestion summary (By facility voltage): January through September 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	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	24	0
500	$101.9	($203.9)	$12.9	$318.7	($1.5)	($14.7)	($12.8)	$0.4	$319.1	9,546	2,784
345	$24.8	($45.8)	$31.7	$102.2	($4.3)	$4.3	($50.0)	($58.7)	$43.6	6,050	1,688
230	$38.5	($27.6)	$7.7	$73.9	($12.6)	$5.3	($5.0)	($22.9)	$50.9	12,123	1,617
138	$61.4	($113.9)	$21.4	$196.7	($13.3)	$7.6	($53.7)	($74.6)	$122.1	22,051	5,587
115	$9.3	($1.1)	$0.3	$10.7	$0.4	$0.6	($0.2)	($0.5)	$10.2	4,429	531
69	$6.9	$0.9	$0.2	$6.2	($3.7)	$0.9	($0.1)	($4.7)	$1.5	4,150	326
34	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	50	2
12	$0.2	$0.2	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	640	0
Unclassifed	$2.7	$6.2	($0.4)	($3.9)	$0.0	$0.0	$0.0	$0.0	($3.9)	NA	NA
Total	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$543.6	59,063	12,535

Constraint Duration

Table 7-9 Top 25 constraints with frequent occurrence: January through September 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	2,559	3,512	953	423	1,251	828	39%	54%	15%	6%	19%	13%
2	Athenia - Saddlebrook	Line	1,094	2,947	1,853	139	331	192	17%	45%	28%	2%	5%	3%
3	East Frankfort - Crete	Line	1,490	2,242	752	219	797	578	23%	34%	11%	3%	12%	9%
4	Waterman - West Dekalb	Line	1,216	2,543	1,327	41	288	247	19%	39%	20%	1%	4%	4%
5	Tiltonsville - Windsor	Line	1,258	1,954	696	237	410	173	19%	30%	11%	4%	6%	3%
6	Pleasant Valley - Belvidere	Line	2,342	1,775	(567)	266	355	89	36%	27%	(9%)	4%	5%	1%
7	5004/5005 Interface	Interface	643	1,379	736	241	561	320	10%	21%	11%	4%	9%	5%
8	Bedington - Black Oak	Interface	395	1,819	1,424	61	47	(14)	6%	28%	22%	1%	1%	(0%)
9	Electric Jct - Nelson	Line	819	1,454	635	202	236	34	13%	22%	10%	3%	4%	1%
10	Cloverdale - Lexington	Line	752	1,044	292	335	620	285	11%	16%	4%	5%	9%	4%
11	Danville - East Danville	Line	165	1,307	1,142	36	138	102	3%	20%	17%	1%	2%	2%
12	Branchburg - Readington	Line	21	1,210	1,189	10	184	174	0%	18%	18%	0%	3%	3%
13	Pleasant Prairie - Zion	Flowgate	51	1,098	1,047	45	212	167	1%	17%	16%	1%	3%	3%
14	Doubs	Transformer	84	806	722	30	423	393	1%	12%	11%	0%	6%	6%
15	Belmont	Transformer	610	1,057	447	71	109	38	9%	16%	7%	1%	2%	1%
16	Mount Storm - Pruntytown	Line	525	571	46	132	574	442	8%	9%	1%	2%	9%	7%
17	Pinehill - Stratford	Line	1,020	1,138	118	0	0	0	16%	17%	2%	0%	0%	0%
18	Lindenwold - Stratford	Line	215	1,119	904	0	0	0	3%	17%	14%	0%	0%	0%
19	Burlington - Croydon	Line	2,420	1,034	(1,386)	3	33	30	37%	16%	(21%)	0%	1%	0%
20	Nelson - Cordova	Line	0	965	965	17	90	73	0%	15%	15%	0%	1%	1%
21	Crete - St Johns Tap	Flowgate	732	800	68	190	245	55	11%	12%	1%	3%	4%	1%
22	Leonia - New Milford	Line	3,088	1,028	(2,060)	39	6	(33)	47%	16%	(31%)	1%	0%	(1%)
23	Beechwood - Kerr Dam	Line	632	582	(50)	228	306	78	10%	9%	(1%)	3%	5%	1%
24	Wylie Ridge	Transformer	354	479	125	335	376	41	5%	7%	2%	5%	6%	1%
25	Mahans Lane - Tidd	Line	72	646	574	24	207	183	1%	10%	9%	0%	3%	3%

Table 7-10 Top 25 constraints with largest year-to-year change in occurrence: January through September 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	3,674	0	(3,674)	1,328	0	(1,328)	56%	0%	(56%)	20%	0%	(20%)
2	Dunes Acres - Michigan City	Flowgate	2,888	142	(2,746)	907	3	(904)	44%	2%	(42%)	14%	0%	(14%)
3	Leonia - New Milford	Line	3,088	1,028	(2,060)	39	6	(33)	47%	16%	(31%)	1%	0%	(1%)
4	Athenia - Saddlebrook	Line	1,094	2,947	1,853	139	331	192	17%	45%	28%	2%	5%	3%
5	AP South	Interface	2,559	3,512	953	423	1,251	828	39%	54%	15%	6%	19%	13%
6	Waterman - West Dekalb	Line	1,216	2,543	1,327	41	288	247	19%	39%	20%	1%	4%	4%
7	Bedington - Black Oak	Interface	395	1,819	1,424	61	47	(14)	6%	28%	22%	1%	1%	(0%)
8	Branchburg - Readington	Line	21	1,210	1,189	10	184	174	0%	18%	18%	0%	3%	3%
9	Burlington - Croydon	Line	2,420	1,034	(1,386)	3	33	30	37%	16%	(21%)	0%	1%	0%
10	East Frankfort - Crete	Line	1,490	2,242	752	219	797	578	23%	34%	11%	3%	12%	9%
11	Danville - East Danville	Line	165	1,307	1,142	36	138	102	3%	20%	17%	1%	2%	2%
12	Pleasant Prairie - Zion	Flowgate	51	1,098	1,047	45	212	167	1%	17%	16%	1%	3%	3%
13	Pana North	Flowgate	879	0	(879)	318	0	(318)	13%	0%	(13%)	5%	0%	(5%)
14	Doubs	Transformer	84	806	722	30	423	393	1%	12%	11%	0%	6%	6%
15	Kammer - Ormet	Line	552	0	(552)	509	3	(506)	8%	0%	(8%)	8%	0%	(8%)
16	5004/5005 Interface	Interface	643	1,379	736	241	561	320	10%	21%	11%	4%	9%	5%
17	Nelson - Cordova	Line	0	965	965	17	90	73	0%	15%	15%	0%	1%	1%
18	Oak Grove - Galesburg	Flowgate	645	61	(584)	531	116	(415)	10%	1%	(9%)	8%	2%	(6%)
19	Pumphrey - Westport	Line	1,179	242	(937)	0	0	0	18%	4%	(14%)	0%	0%	0%
20	Lindenwold - Stratford	Line	215	1,119	904	0	0	0	3%	17%	14%	0%	0%	0%
21	Tiltonsville - Windsor	Line	1,258	1,954	696	237	410	173	19%	30%	11%	4%	6%	3%
22	Ruth - Turner	Line	704	88	(616)	279	36	(243)	11%	1%	(9%)	4%	1%	(4%)
23	Redoak - Sayreville	Line	59	795	736	7	57	50	1%	12%	11%	0%	1%	1%
24	Marktown - Inland Steel	Flowgate	0	424	424	0	344	344	0%	6%	6%	0%	5%	5%
25	Rising	Flowgate	0	776	776	55	44	(11)	0%	12%	12%	1%	1%	(0%)

Constraint Costs

Table 7-11 Top 25 constraints affecting annual PJM congestion costs (By facility): January through September 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	$4.3	($335.3)	$1.5	$341.1	$9.6	$6.9	($1.7)	$1.1	$342.2	30%
2	Bedington - Black Oak	Interface	500	$12.6	($70.3)	$2.1	$85.0	$0.0	($0.9)	($0.5)	$0.5	$85.5	7%
3	5004/5005 Interface	Interface	500	$43.4	($32.4)	($0.1)	$75.7	$9.7	$8.5	($0.5)	$0.7	$76.4	7%
4	Doubs	Transformer	AP	$35.3	($29.5)	$0.3	$65.1	$0.8	$1.9	($2.2)	($3.3)	$61.8	5%
5	AEP-DOM	Interface	500	$9.8	($37.6)	$0.9	$48.3	$0.1	($1.3)	($0.1)	$1.3	$49.6	4%
6	Cloverdale - Lexington	Line	AEP	$16.5	($13.3)	$2.8	$32.6	($3.1)	($3.6)	($4.6)	($4.2)	$28.4	2%
7	East Frankfort - Crete	Line	ComEd	$4.1	($29.3)	$3.9	$37.2	($4.0)	$0.4	($6.6)	($11.0)	$26.2	2%
8	Brandon Shores - Riverside	Line	BGE	$16.8	($10.4)	($0.4)	$26.8	$0.9	$2.4	$0.5	($1.0)	$25.8	2%
9	Mount Storm - Pruntytown	Line	AP	$3.7	($18.8)	$2.1	$24.6	$0.4	($4.6)	($4.7)	$0.3	$24.9	2%
10	West	Interface	500	$20.8	($1.7)	($0.2)	$22.3	$0.6	$1.2	$0.1	($0.5)	$21.7	2%
11	Tiltonsville - Windsor	Line	AP	$16.5	($2.0)	$1.0	$19.6	($3.6)	$0.2	($0.0)	($3.9)	$15.7	1%
12	Brunner Island - Yorkana	Line	Met-Ed	($1.8)	($14.3)	$0.4	$12.9	$0.7	($1.1)	($0.9)	$0.9	$13.7	1%
13	Belmont	Transformer	AP	$6.8	($6.2)	($0.8)	$12.3	($0.1)	($0.4)	($0.1)	$0.2	$12.5	1%
14	Clover	Transformer	Dominion	$3.4	($9.6)	$1.8	$14.8	($1.2)	($0.8)	($2.2)	($2.5)	$12.3	1%
15	Crescent	Transformer	DLCO	$7.5	($3.9)	$0.6	$12.0	$0.2	($0.6)	($0.6)	$0.2	$12.2	1%
16	Branchburg - Readington	Line	PSEG	$5.0	($7.9)	$0.6	$13.6	($0.7)	$1.4	$0.1	($1.9)	$11.6	1%
17	Crete - St Johns Tap	Flowgate	Midwest ISO	($1.2)	($15.3)	($0.2)	$13.9	($0.9)	($0.2)	($1.8)	($2.5)	$11.4	1%
18	Electric Jct - Nelson	Line	ComEd	($8.7)	($32.5)	$6.7	$30.4	($0.3)	$3.6	($16.1)	($20.0)	$10.4	1%
19	Pleasant Valley - Belvidere	Line	ComEd	($7.0)	($20.9)	$1.9	$15.8	$0.1	$2.7	($3.6)	($6.2)	$9.7	1%
20	Eddystone - Island Road	Line	PECO	$0.7	($7.8)	$1.1	$9.6	($0.0)	$0.0	$0.0	($0.0)	$9.5	1%
21	Hunterstown	Transformer	Met-Ed	$4.3	($3.9)	$0.3	$8.4	$0.1	$0.0	($0.0)	$0.0	$8.5	1%
22	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($3.2)	($7.5)	$2.4	$6.7	($0.4)	$1.2	($13.3)	($14.9)	($8.1)	(1%)
23	Limerick	Transformer	PECO	$1.1	($2.2)	($0.1)	$3.2	$0.8	($3.4)	($0.1)	$4.1	$7.3	1%
24	Graceton - Raphael Road	Line	BGE	($2.6)	($8.2)	$0.6	$6.1	$0.6	($0.7)	($0.2)	$1.1	$7.2	1%
25	Nipetown - Reid	Line	AP	$1.7	($5.0)	$0.3	$6.9	$0.0	($0.1)	($0.1)	$0.0	$6.9	1%

Table 7-12 Top 25 constraints affecting annual PJM congestion costs (By facility): January through September 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	$8.8	($133.2)	($0.3)	$141.7	$2.2	($3.1)	$2.2	$7.5	$149.1	27%
2	West	Interface	500	$17.8	($21.4)	$0.6	$39.7	$0.3	($0.2)	$0.1	$0.7	$40.4	7%
3	5004/5005 Interface	Interface	500	$9.5	($25.5)	$0.1	$35.2	$1.3	$0.4	$0.1	$1.0	$36.2	7%
4	Kammer	Transformer	500	$50.8	$16.1	$9.0	$43.8	($4.9)	($6.7)	($11.6)	($9.8)	$34.0	6%
5	Pleasant Valley - Belvidere	Line	ComEd	($4.0)	($29.4)	$2.9	$28.3	$0.8	$1.9	($4.1)	($5.1)	$23.3	4%
6	East Frankfort - Crete	Line	ComEd	$4.7	($12.8)	$7.4	$24.9	($0.6)	($0.0)	($3.4)	($4.0)	$20.9	4%
7	Mount Storm - Pruntytown	Line	AP	$1.8	($16.8)	$0.5	$19.1	$0.9	($1.7)	($1.1)	$1.5	$20.5	4%
8	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$13.5	($22.9)	$8.6	$44.9	($7.2)	($2.0)	($23.4)	($28.6)	$16.3	3%
9	Cloverdale - Lexington	Line	AEP	$6.8	($4.3)	$1.7	$12.9	($0.1)	($3.0)	($2.5)	$0.4	$13.2	2%
10	Bedington - Black Oak	Interface	500	$2.4	($10.4)	$0.6	$13.4	($0.4)	($0.0)	$0.2	($0.3)	$13.1	2%
11	Pana North	Flowgate	Midwest ISO	$0.1	($2.1)	$1.7	$3.9	($0.5)	$1.1	($11.5)	($13.0)	($9.1)	(2%)
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.7	($9.2)	$2.9	$14.7	($0.9)	$0.2	($5.1)	($6.2)	$8.5	2%
13	Ruth - Turner	Line	AEP	$2.5	($6.5)	$0.5	$9.5	($1.3)	($0.7)	($0.6)	($1.2)	$8.3	2%
14	Tiltonsville - Windsor	Line	AP	$7.9	($0.3)	$0.3	$8.5	($0.3)	($0.6)	($0.8)	($0.5)	$7.9	1%
15	Kanawha River	Transformer	AEP	$2.0	($3.6)	$0.3	$5.9	$0.1	($0.5)	($0.1)	$0.5	$6.4	1%
16	Kammer - Ormet	Line	AEP	$4.3	($4.1)	($0.1)	$8.3	($1.6)	$0.5	($0.0)	($2.2)	$6.2	1%
17	Sammis - Wylie Ridge	Line	AP	$3.1	($2.7)	$3.4	$9.2	($1.1)	($0.3)	($2.8)	($3.5)	$5.7	1%
18	Kanawha - Kincaid	Line	AEP	$1.9	($3.5)	$0.2	$5.6	$0.0	$0.0	$0.0	$0.0	$5.6	1%
19	Graceton - Raphael Road	Line	BGE	$0.9	($3.6)	$0.5	$5.1	$1.5	$0.3	($0.6)	$0.6	$5.6	1%
20	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%)
21	Breed - Wheatland	Line	AEP	($0.2)	($4.9)	$0.6	$5.3	$0.0	($0.0)	($0.0)	($0.0)	$5.3	1%
22	Electric Jct - Nelson	Line	ComEd	$0.0	($8.4)	$1.2	$9.6	$1.8	$1.7	($4.8)	($4.7)	$4.9	1%
23	Kanawha River - Bradley	Line	AEP	($0.1)	($4.6)	$0.3	$4.7	($0.0)	$0.1	($0.0)	($0.1)	$4.7	1%
24	Mount Storm	Transformer	AP	$0.8	($3.9)	($0.1)	$4.7	($0.1)	$0.1	$0.1	($0.2)	$4.5	1%
25	Doubs	Transformer	AP	$2.6	($1.8)	$0.0	$4.4	($0.0)	($0.1)	($0.1)	($0.1)	$4.3	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 September 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	Crete - St Johns Tap	($1.2)	($15.3)	($0.2)	$13.9	($0.9)	($0.2)	($1.8)	($2.5)	$11.4	800	245
2	Pleasant Prairie - Zion	($3.2)	($7.5)	$2.4	$6.7	($0.4)	$1.2	($13.3)	($14.9)	($8.1)	1,098	212
3	Rising	$0.2	($4.3)	$0.6	$5.1	($0.0)	$0.0	($0.2)	($0.3)	$4.8	776	44
4	Palisades - Vergennes	$2.8	($0.6)	$0.5	$3.9	($0.1)	$0.4	($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	($0.7)	$0.6	$1.5	($0.0)	($0.0)	($0.0)	($0.0)	$1.5	376	1
7	Marktown - Inland Steel	$0.6	($0.9)	$0.7	$2.2	($0.9)	$0.7	($1.4)	($3.1)	($0.9)	424	344
8	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.7)	($0.7)	($0.7)	0	24
9	Benton Harbor - Palisades	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	($0.3)	($0.6)	($0.6)	0	32
10	Beaver Valley - Sammis	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.2)	($0.4)	($0.4)	0	8
11	Oak Grove - Galesburg	($0.1)	($0.3)	$0.1	$0.3	($0.0)	$0.1	($0.6)	($0.7)	($0.4)	61	116
12	Michigan City - Laporte	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.3)	($0.4)	($0.4)	0	36
13	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	21
14	Burr Oak	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.2	($0.5)	($0.6)	($0.4)	76	103
15	Lanesville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.3)	($0.4)	($0.4)	0	38
16	Stillwell - Dumont	$0.0	($0.2)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	42	0
17	Bunsonville - Eugene	($0.0)	($0.3)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	31	0
18	DC Cook - Palisades	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.0)	($0.2)	($0.3)	($0.3)	0	6
19	Palisades - Roosevelt	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.2)	($0.3)	($0.3)	0	30
20	Cumberland - Bush	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.2)	($0.2)	($0.2)	0	18

Table 7-14 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through September 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	Dunes Acres - Michigan City	$13.5	($22.9)	$8.6	$44.9	($7.2)	($2.0)	($23.4)	($28.6)	$16.3	2,888	907
2	Pana North	$0.1	($2.1)	$1.7	$3.9	($0.5)	$1.1	($11.5)	($13.0)	($9.1)	879	318
3	Crete - St Johns Tap	$2.7	($9.2)	$2.9	$14.7	($0.9)	$0.2	($5.1)	($6.2)	$8.5	732	190
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	$0.7	($3.2)	($3.8)	($3.8)	0	161
6	Pleasant Prairie - Zion	($0.0)	($0.2)	$0.2	$0.4	$0.1	$0.6	($3.2)	($3.7)	($3.3)	51	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	($0.5)	($3.8)	$0.1	$3.4	$0.7	$1.1	($4.0)	($4.5)	($1.1)	645	531
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	Rising	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.5)	($0.5)	($0.5)	0	55
11	State Line - Wolf Lake	$0.3	($1.0)	$0.6	$1.9	($0.4)	$0.5	($1.5)	($2.4)	($0.5)	415	152
12	Pawnee	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.4)	($0.4)	($0.4)	0	35
13	Lanesville	$0.3	($0.1)	$0.1	$0.5	$0.0	$0.1	($0.8)	($0.9)	($0.4)	104	32
14	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.3	($0.0)	($0.4)	($0.4)	0	5
15	Palisades - Argenta	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.2	($0.0)	($0.2)	($0.2)	0	8
16	Bunsonville - Eugene	$0.0	($0.1)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
17	Burr Oak	$0.1	($0.2)	$0.4	$0.7	($0.2)	$0.0	($0.6)	($0.9)	($0.2)	24	37
18	State Line	$0.0	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	295	0
19	Havana - Ipava	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	9
20	Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	2

Congestion-Event Summary for the 500 kV System

Table 7-15 Regional constraints summary (By facility): January through September 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	$4.3	($335.3)	$1.5	$341.1	$9.6	$6.9	($1.7)	$1.1	$342.2	3,512	1,251
2	Bedington - Black Oak	Interface	500	$12.6	($70.3)	$2.1	$85.0	$0.0	($0.9)	($0.5)	$0.5	$85.5	1,819	47
3	5004/5005 Interface	Interface	500	$43.4	($32.4)	($0.1)	$75.7	$9.7	$8.5	($0.5)	$0.7	$76.4	1,379	561
4	AEP-DOM	Interface	500	$9.8	($37.6)	$0.9	$48.3	$0.1	($1.3)	($0.1)	$1.3	$49.6	471	89
5	West	Interface	500	$20.8	($1.7)	($0.2)	$22.3	$0.6	$1.2	$0.1	($0.5)	$21.7	159	58
6	Harrison - Pruntytown	Line	500	$2.0	($4.1)	$0.8	$6.9	($0.7)	($0.4)	($2.3)	($2.6)	$4.3	231	224
7	East	Interface	500	$1.4	($1.8)	$0.0	$3.2	($0.0)	$0.0	$0.0	($0.0)	$3.2	154	1
8	Central	Interface	500	$1.1	($0.2)	$0.1	$1.4	$0.1	$0.1	($0.0)	($0.0)	$1.4	116	13
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	$0.5	$0.7	$0.2	($0.1)	($0.1)	0	45
11	Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	1

Table 7-16 Regional constraints summary (By facility): January through September 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	$8.8	($133.2)	($0.3)	$141.7	$2.2	($3.1)	$2.2	$7.5	$149.1	2,559	423
2	West	Interface	500	$17.8	($21.4)	$0.6	$39.7	$0.3	($0.2)	$0.1	$0.7	$40.4	391	85
3	5004/5005 Interface	Interface	500	$9.5	($25.5)	$0.1	$35.2	$1.3	$0.4	$0.1	$1.0	$36.2	643	241
4	Kammer	Transformer	500	$50.8	$16.1	$9.0	$43.8	($4.9)	($6.7)	($11.6)	($9.8)	$34.0	3,674	1,328
5	Bedington - Black Oak	Interface	500	$2.4	($10.4)	$0.6	$13.4	($0.4)	($0.0)	$0.2	($0.3)	$13.1	395	61
6	AEP-DOM	Interface	500	$0.5	($3.1)	$0.3	$3.9	($0.5)	($0.0)	($0.3)	($0.8)	$3.1	126	64
7	East	Interface	500	$0.2	($0.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	21	0
8	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.0	$0.1	$0.1	0	18
9	Central	Interface	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	$0.1	19	8
10	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 September 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	$33.5	$12.0	$0.2	$21.8	($0.7)	($1.0)	($0.1)	$0.2	$22.0
AEP	($122.6)	($278.8)	$11.8	$168.0	($10.1)	$19.7	($16.1)	($45.8)	$122.2
AP	($4.4)	($241.7)	$1.7	$238.9	$10.4	$19.5	($3.3)	($12.4)	$226.5
BGE	$159.4	$92.4	$6.0	$72.9	$10.7	($3.7)	($7.8)	$6.6	$79.6
ComEd	($333.8)	($546.2)	$4.5	$216.9	($20.7)	$12.1	($12.5)	($45.3)	$171.6
DAY	($14.8)	($23.4)	$6.1	$14.7	$1.0	$1.0	($6.8)	($6.8)	$7.9
DLCO	($67.6)	($105.6)	($0.2)	$37.7	($8.9)	($0.3)	$0.2	($8.4)	$29.3
Dominion	$218.4	($4.1)	$12.7	$235.2	($3.3)	($5.5)	($12.8)	($10.5)	$224.7
DPL	$57.2	$20.6	$0.7	$37.4	($0.5)	$1.1	($1.0)	($2.7)	$34.7
External	($142.3)	($151.2)	($5.8)	$3.2	$7.1	($18.4)	($25.2)	$0.3	$3.5
JCPL	$56.3	$20.2	$0.4	$36.5	$2.8	($0.2)	($0.5)	$2.5	$39.0
Met-Ed	$50.8	$37.1	$0.9	$14.6	($0.9)	($0.3)	($1.1)	($1.8)	$12.8
PECO	$56.5	$62.0	$0.3	($5.3)	($2.6)	$0.9	($0.8)	($4.3)	($9.6)
PENELEC	($61.7)	($142.6)	$0.2	$81.1	$22.4	$11.0	$0.1	$11.5	$92.6
Pepco	$285.0	$198.9	$4.9	$91.0	($22.9)	($12.4)	($5.7)	($16.2)	$74.8
PPL	$74.5	$83.7	$2.9	($6.2)	$9.6	$7.5	($0.6)	$1.4	($4.8)
PSEG	$96.1	$73.6	$21.4	$43.9	($3.2)	$10.7	($18.3)	($32.2)	$11.7
RECO	$2.8	$0.2	$0.0	$2.7	$0.6	($0.0)	($0.0)	$0.6	$3.3
Total	$343.4	($892.9)	$68.6	$1,305.0	($9.3)	$41.7	($112.4)	($163.4)	$1,141.6

Table 7-18 Congestion cost summary (By control zone): January through September 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	$21.7	$8.0	$0.2	$13.9	($0.5)	$0.8	$0.4	($0.9)	$12.9
AEP	($46.4)	($129.4)	$8.7	$91.8	($5.1)	$7.5	($10.7)	($23.4)	$68.4
AP	$32.3	($54.0)	$13.3	$99.5	($4.6)	$2.7	($22.6)	($29.9)	$69.7
BGE	$71.8	$57.2	$1.1	$15.7	$5.3	($3.7)	($1.2)	$7.9	$23.6
ComEd	($206.4)	($386.3)	($3.3)	$176.7	($5.8)	$2.1	($0.7)	($8.6)	$168.1
DAY	($8.0)	($15.1)	($0.5)	$6.7	$1.0	$1.3	$0.1	($0.2)	$6.5
DLCO	($41.4)	($62.5)	($0.0)	$21.1	($3.7)	$5.1	($0.0)	($8.8)	$12.3
Dominion	$73.8	($0.8)	$6.3	$80.8	$0.2	($3.9)	($7.6)	($3.4)	$77.4
DPL	$43.7	$13.0	$0.4	$31.1	($2.0)	$1.5	($0.4)	($4.0)	$27.1
External	($18.0)	($46.3)	$32.2	$60.6	($2.0)	($5.6)	($71.2)	($67.6)	($7.0)
JCPL	$40.2	$16.3	$0.0	$23.9	$0.4	($2.4)	($0.1)	$2.7	$26.6
Met-Ed	$31.1	$32.1	$0.2	($0.7)	($0.1)	($0.5)	($0.3)	$0.1	($0.6)
PECO	$16.4	$32.2	$0.1	($15.8)	($0.3)	$2.5	($0.0)	($2.8)	($18.6)
PENELEC	($2.7)	($27.1)	$0.3	$24.7	$1.2	$1.0	($0.1)	$0.0	$24.7
Pepco	$158.9	$106.0	$2.3	$55.3	($18.8)	($8.6)	($2.5)	($12.7)	$42.6
PPL	$11.9	$19.3	$2.3	($5.1)	$0.1	($0.6)	$0.3	$0.9	($4.2)
PSEG	$64.9	$52.4	$10.1	$22.6	($0.4)	$4.9	($5.0)	($10.3)	$12.4
RECO	$2.0	$0.0	$0.1	$2.0	($0.0)	($0.0)	($0.1)	($0.1)	$1.9
Total	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$543.6

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 September 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	5004/5005 Interface	Interface	500	$8.2	$3.7	$0.0	$4.5	$0.6	($0.7)	($0.0)	$1.2	$5.8	1,379	561
2	England - Middletap	Line	AECO	$4.0	$0.7	$0.0	$3.3	($0.4)	($0.4)	($0.0)	($0.0)	$3.2	336	69
3	West	Interface	500	$3.7	$1.8	$0.0	$1.8	$0.1	$0.0	$0.0	$0.1	$2.0	159	58
4	Monroe	Transformer	AECO	$1.7	$0.2	$0.0	$1.5	$0.1	($0.2)	($0.0)	$0.2	$1.8	232	48
5	Brandon Shores - Riverside	Line	BGE	$2.4	$1.1	$0.0	$1.3	$0.0	($0.2)	($0.0)	$0.2	$1.5	343	162
6	Absecon - Lewis	Line	AECO	$0.2	$0.0	$0.0	$0.2	($1.5)	$0.1	($0.1)	($1.6)	($1.4)	81	18
7	AP South	Interface	500	$1.9	$0.9	$0.0	$1.0	$0.1	($0.0)	($0.0)	$0.1	$1.1	3,512	1,251
8	Shieldalloy - Vineland	Line	AECO	$3.2	$0.9	$0.1	$2.3	($1.2)	$0.1	($0.0)	($1.3)	$1.1	229	163
9	Branchburg - Readington	Line	PSEG	($1.3)	($0.5)	($0.0)	($0.8)	($0.1)	$0.0	$0.0	($0.1)	($0.8)	1,210	184
10	Graceton - Raphael Road	Line	BGE	($1.2)	($0.5)	($0.0)	($0.7)	($0.0)	$0.1	$0.0	($0.1)	($0.8)	215	112
11	East Frankfort - Crete	Line	ComEd	$0.9	$0.2	$0.0	$0.6	$0.1	($0.0)	($0.0)	$0.2	$0.8	2,242	797
12	Bedington - Black Oak	Interface	500	$1.3	$0.6	$0.0	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	1,819	47
13	Cloverdale - Lexington	Line	AEP	$0.8	$0.3	$0.0	$0.5	$0.2	$0.0	($0.0)	$0.2	$0.7	1,044	620
14	Tiltonsville - Windsor	Line	AP	$1.0	$0.4	$0.0	$0.6	$0.1	($0.1)	($0.0)	$0.1	$0.7	1,954	410
15	Brunner Island - Yorkana	Line	Met-Ed	($0.6)	($0.2)	($0.0)	($0.4)	($0.1)	$0.1	$0.0	($0.2)	($0.6)	219	168
23	Corson - Court	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.0)	($0.3)	($0.3)	7	15
34	Corson - Union	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.2	$0.2	0	16
40	Sherman Avenue	Transformer	AECO	$0.1	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	25	0
66	Sherman	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.0)	($0.1)	($0.1)	0	19
71	Corson	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	0	17

Table 7-20 AECO Control Zone top congestion cost impacts (By facility): January through September 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	Kammer	Transformer	500	$4.2	$1.3	$0.0	$2.9	$0.2	($0.0)	$0.0	$0.3	$3.1	3,674	1,328
2	West	Interface	500	$4.6	$2.2	$0.0	$2.4	$0.0	($0.0)	($0.0)	$0.0	$2.4	391	85
3	5004/5005 Interface	Interface	500	$3.8	$1.7	$0.0	$2.1	$0.1	$0.1	$0.0	$0.1	$2.2	643	241
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.4	$0.3	$0.0	$1.1	$0.1	($0.0)	$0.0	$0.2	$1.3	2,888	907
5	Wylie Ridge	Transformer	AP	$1.8	$0.9	$0.0	$0.9	($0.0)	$0.1	$0.1	($0.0)	$0.9	354	335
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	($1.2)	($0.4)	($0.0)	($0.8)	$0.2	$0.1	$0.0	$0.0	($0.8)	300	127
8	AP South	Interface	500	$1.0	$0.5	$0.0	$0.6	$0.0	$0.0	$0.1	$0.1	$0.6	2,559	423
9	Monroe	Transformer	AECO	$0.5	$0.0	$0.0	$0.4	$0.1	($0.0)	$0.0	$0.1	$0.5	263	13
10	Shieldalloy - Vineland	Line	AECO	$1.1	$0.3	$0.0	$0.9	($0.3)	$0.1	($0.0)	($0.4)	$0.5	148	61
11	Monroe - New Freedom	Line	AECO	$0.8	$0.4	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	584	0
12	Tiltonsville - Windsor	Line	AP	$0.6	$0.2	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.1	$0.4	1,258	237
13	East Frankfort - Crete	Line	ComEd	$0.5	$0.2	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	1,490	219
14	Sammis - Wylie Ridge	Line	AP	$0.6	$0.2	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.4	632	140
15	Cloverdale - Lexington	Line	AEP	$0.4	$0.2	$0.0	$0.2	$0.1	($0.0)	$0.0	$0.1	$0.3	752	335
19	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
28	Corson - Union	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	3
75	Clayton - Williams	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
125	Churchtown	Transformer	AECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
140	Carlls Corner - Sherman Ave	Line	AECO	$0.0	$0.0	($0.0)	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	24	11

BGE Control Zone

Table 7-21 BGE Control Zone top congestion cost impacts (By facility): January through September 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	Brandon Shores - Riverside	Line	BGE	$17.3	($8.9)	$0.2	$26.4	($2.1)	$0.2	($0.3)	($2.5)	$23.9	343	162
2	AP South	Interface	500	$46.9	$36.1	$1.9	$12.6	$3.5	($1.5)	($1.6)	$3.4	$16.0	3,512	1,251
3	Doubs	Transformer	AP	$11.7	$7.0	$0.2	$5.0	$1.0	($1.2)	($0.4)	$1.8	$6.8	806	431
4	Bedington - Black Oak	Interface	500	$18.3	$13.6	$0.6	$5.3	$0.4	($0.2)	($0.1)	$0.5	$5.8	1,819	47
5	5004/5005 Interface	Interface	500	$7.5	$3.7	$0.3	$4.1	$0.5	($0.2)	($0.3)	$0.4	$4.5	1,379	561
6	West	Interface	500	$6.3	$3.1	$0.0	$3.2	$0.2	($0.0)	($0.0)	$0.2	$3.4	159	58
7	Graceton - Raphael Road	Line	BGE	$5.1	$3.3	$0.3	$2.2	$0.2	($0.5)	($0.3)	$0.4	$2.5	215	112
8	Mount Storm - Pruntytown	Line	AP	$4.3	$3.6	$0.2	$0.8	$1.3	($0.7)	($0.6)	$1.4	$2.2	571	574
9	Brunner Island - Yorkana	Line	Met-Ed	$3.6	$2.2	$0.2	$1.7	$0.2	($0.0)	($0.2)	($0.1)	$1.6	219	168
10	Cloverdale - Lexington	Line	AEP	$4.8	$4.4	$0.2	$0.5	$0.8	($0.3)	($0.2)	$0.9	$1.4	1,044	620
11	Tiltonsville - Windsor	Line	AP	$2.4	$1.6	$0.1	$0.8	$0.2	($0.1)	($0.1)	$0.2	$1.0	1,954	410
12	East Frankfort - Crete	Line	ComEd	$2.5	$2.0	$0.1	$0.6	$0.3	($0.1)	($0.0)	$0.3	$0.9	2,242	797
13	Pumphrey	Transformer	Pepco	$1.1	$0.3	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	56	0
14	Five Forks - Rock Ridge	Line	Dominion	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.5	($0.1)	($0.9)	($0.9)	0	38
15	Branchburg - Readington	Line	PSEG	($1.5)	($0.9)	($0.1)	($0.8)	($0.1)	$0.1	$0.1	($0.0)	($0.8)	1,210	184
25	Fullerton - Windyedge	Line	BGE	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	23	0
30	Green Street - Westport	Line	BGE	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	144	0
43	Granite - Harrisonville	Line	BGE	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	7	0
48	Glenarm - Windy Edge	Line	BGE	$0.2	$0.1	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.2	18	16
49	High Ridge - Howard	Line	BGE	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	9	10

Table 7-22 BGE Control Zone top congestion cost impacts (By facility): January through September 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	Kammer	Transformer	500	$11.9	$9.0	$0.2	$3.2	$1.0	($0.6)	($0.2)	$1.3	$4.5	3,674	1,328
2	AP South	Interface	500	$18.4	$16.9	$0.2	$1.7	$1.3	($1.0)	($0.2)	$2.1	$3.8	2,559	423
3	5004/5005 Interface	Interface	500	$2.5	$1.3	$0.1	$1.3	$0.2	($0.2)	($0.1)	$0.4	$1.7	643	241
4	West	Interface	500	$8.1	$6.8	$0.2	$1.4	$0.1	($0.2)	($0.0)	$0.2	$1.6	391	85
5	Wylie Ridge	Transformer	AP	$3.6	$3.4	$0.1	$0.3	$0.6	($0.7)	($0.2)	$1.2	$1.5	354	335
6	Graceton - Raphael Road	Line	BGE	$4.3	$2.9	$0.0	$1.4	$0.0	$0.1	($0.1)	($0.2)	$1.3	300	127
7	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.4	$2.7	$0.0	$0.6	$0.3	($0.0)	($0.0)	$0.4	$1.0	2,888	907
8	Mount Storm - Pruntytown	Line	AP	$3.2	$2.9	$0.0	$0.2	$0.5	($0.3)	($0.1)	$0.6	$0.9	525	132
9	Bedington - Black Oak	Interface	500	$2.7	$2.0	$0.1	$0.7	$0.1	($0.0)	($0.0)	$0.1	$0.8	395	61
10	Pumphrey - Westport	Line	Pepco	$0.5	($0.1)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,179	0
11	Cloverdale - Lexington	Line	AEP	$2.3	$2.2	$0.0	$0.2	$0.3	($0.1)	($0.0)	$0.4	$0.5	752	335
12	Tiltonsville - Windsor	Line	AP	$1.2	$0.7	$0.0	$0.4	$0.1	($0.0)	($0.0)	$0.1	$0.5	1,258	237
13	Five Forks - Rock Ridge	Line	BGE	$0.7	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	136	0
14	Buzzard - Ritchie	Line	Pepco	($2.0)	($1.9)	($0.0)	($0.1)	$0.1	$0.2	$0.0	($0.1)	($0.3)	409	149
15	Sammis - Wylie Ridge	Line	AP	$1.4	$1.1	$0.0	$0.3	$0.1	($0.1)	($0.0)	$0.1	$0.4	632	140
18	Green Street - Westport	Line	BGE	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	356	0
22	Conastone - Otter	Line	BGE	$0.4	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	92	32
24	Waugh Chapel	Transformer	BGE	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	$0.0	$0.2	$0.2	0	8
26	Conastone	Transformer	BGE	$0.3	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	17	1
33	Gwynnbrook - Mays Chapel	Line	BGE	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	26	0

DPL Control Zone

Table 7-23 DPL Control Zone top congestion cost impacts (By facility): January through September 2010 (See 2009 SOM, Table 7-23)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$13.4	$5.7	$0.1	$7.8	$0.5	($0.0)	($0.2)	$0.3	$8.1	1,379	561
2	AP South	Interface	500	$5.0	$2.2	$0.1	$2.9	$0.2	$0.0	($0.0)	$0.1	$3.0	3,512	1,251
3	Oak Hall	Transformer	DPL	$2.7	$0.5	$0.0	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	585	0
4	West	Interface	500	$5.3	$3.4	$0.0	$1.9	$0.1	$0.1	($0.0)	$0.0	$1.9	159	58
5	Bedington - Black Oak	Interface	500	$2.7	$1.2	$0.0	$1.6	$0.0	$0.0	($0.0)	($0.0)	$1.5	1,819	47
6	New Church - Piney Grove	Line	DPL	$1.9	$0.4	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	296	0
7	Brandon Shores - Riverside	Line	BGE	$3.4	$2.0	$0.0	$1.5	$0.1	($0.0)	($0.0)	$0.1	$1.5	343	162
8	East Frankfort - Crete	Line	ComEd	$1.6	$0.2	$0.0	$1.4	$0.1	$0.0	($0.0)	$0.0	$1.4	2,242	797
9	Middletown - Mt Pleasant	Line	DPL	$1.7	$0.4	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	163	0
10	Longwood - Wye Mills	Line	DPL	$1.6	$0.3	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	260	0
11	Cloverdale - Lexington	Line	AEP	$1.4	$0.3	$0.0	$1.1	$0.2	$0.0	($0.1)	$0.1	$1.2	1,044	620
12	Graceton - Raphael Road	Line	BGE	($2.1)	($1.0)	($0.0)	($1.1)	($0.0)	($0.1)	$0.0	$0.0	($1.1)	215	112
13	Branchburg - Readington	Line	PSEG	($1.9)	($0.9)	($0.1)	($1.0)	($0.0)	($0.0)	$0.0	$0.1	($1.0)	1,210	184
14	Eddystone - Island Road	Line	PECO	($2.8)	($2.0)	($0.1)	($0.9)	($0.0)	($0.0)	$0.0	$0.0	($0.9)	186	3
15	Tiltonsville - Windsor	Line	AP	$1.5	$0.7	$0.0	$0.8	$0.0	($0.1)	($0.0)	$0.1	$0.9	1,954	410
16	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
17	Kenney - Stockton	Line	DPL	$1.0	$0.3	$0.0	$0.7	($1.5)	($0.1)	($0.1)	($1.4)	($0.8)	96	111
18	Easton - Trappe	Line	DPL	$0.9	$0.2	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	117	0
19	Dupont Seaford - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.4	($0.0)	($0.7)	($0.7)	0	15
20	Keeney At5n	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.6	($0.0)	($0.7)	($0.7)	0	13

Table 7-24 DPL Control Zone top congestion cost impacts (By facility): January through September 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	Kammer	Transformer	500	$7.5	$1.7	$0.0	$5.9	($0.1)	$0.3	($0.1)	($0.4)	$5.4	3,674	1,328
2	West	Interface	500	$8.6	$3.6	$0.0	$5.1	($0.0)	$0.1	($0.0)	($0.1)	$4.9	391	85
3	5004/5005 Interface	Interface	500	$6.2	$2.5	$0.1	$3.8	$0.0	$0.3	($0.1)	($0.3)	$3.5	643	241
4	Short - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.2	($0.1)	($2.4)	($2.4)	0	27
5	Wylie Ridge	Transformer	AP	$3.4	$1.3	$0.0	$2.1	$0.2	$0.2	($0.0)	($0.0)	$2.1	354	335
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.4	$0.3	($0.0)	$2.1	($0.1)	$0.0	$0.0	($0.1)	$2.0	2,888	907
7	AP South	Interface	500	$2.6	$0.8	$0.0	$1.8	$0.0	$0.1	($0.0)	($0.1)	$1.7	2,559	423
8	Middletown - Mt Pleasant	Line	DPL	$1.8	$0.3	$0.0	$1.5	($0.2)	$0.0	$0.0	($0.2)	$1.3	300	17
9	Sammis - Wylie Ridge	Line	AP	$1.2	$0.2	$0.0	$1.0	($0.0)	$0.0	($0.0)	($0.1)	$0.9	632	140
10	Graceton - Raphael Road	Line	BGE	($1.9)	($0.5)	($0.0)	($1.5)	$0.3	($0.2)	$0.0	$0.6	($0.9)	300	127
11	North Seaford - Pine Street	Line	DPL	$1.0	$0.2	$0.0	$0.8	($0.0)	($0.0)	($0.0)	$0.0	$0.8	310	1
12	East Frankfort - Crete	Line	ComEd	$1.0	$0.2	$0.0	$0.8	$0.0	$0.0	$0.0	($0.0)	$0.8	1,490	219
13	Tiltonsville - Windsor	Line	AP	$1.0	$0.2	$0.0	$0.8	($0.0)	$0.0	($0.0)	($0.1)	$0.7	1,258	237
14	Cloverdale - Lexington	Line	AEP	$0.9	$0.2	$0.0	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.7	752	335
15	Easton - Trappe	Line	DPL	$0.7	$0.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	146	0
16	Church - I.B. Corners	Line	DPL	$0.7	$0.1	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.0)	$0.6	55	5
17	Longwood - Wye Mills	Line	DPL	$0.6	$0.1	$0.0	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	240	3
19	Edgemoor - Harmony	Line	DPL	$0.8	$0.3	$0.0	$0.5	($0.1)	($0.0)	($0.0)	($0.1)	$0.4	28	7
20	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
21	Edgemoor At20	Transformer	DPL	$0.9	$0.4	$0.0	$0.5	($0.4)	$0.4	($0.1)	($0.9)	($0.4)	36	43

JCPL Control Zone

Table 7-25 JCPL Control Zone top congestion cost impacts (By facility): January through September 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	$18.1	$8.1	$0.0	$10.1	$1.0	($0.2)	($0.1)	$1.1	$11.2	1,379	561
2	Branchburg - Readington	Line	PSEG	$6.8	$0.4	$0.1	$6.5	($0.5)	($0.3)	$0.1	($0.2)	$6.3	1,210	184
3	West	Interface	500	$7.5	$4.0	$0.0	$3.6	$0.0	($0.1)	($0.0)	$0.2	$3.7	159	58
4	Redoak - Sayreville	Line	JCPL	($1.9)	($5.5)	$0.0	$3.6	$0.1	$0.7	$0.0	($0.6)	$3.0	795	57
5	Athenia - Saddlebrook	Line	PSEG	($3.2)	($1.0)	($0.0)	($2.2)	($0.2)	$0.1	$0.0	($0.2)	($2.4)	2,947	331
6	Brandon Shores - Riverside	Line	BGE	$4.5	$2.4	$0.0	$2.2	$0.1	($0.1)	($0.0)	$0.1	$2.3	343	162
7	East Frankfort - Crete	Line	ComEd	$2.1	$0.9	($0.0)	$1.1	$0.0	($0.1)	$0.0	$0.1	$1.3	2,242	797
8	Tiltonsville - Windsor	Line	AP	$2.2	$1.1	$0.0	$1.0	$0.0	($0.1)	($0.0)	$0.1	$1.1	1,954	410
9	Graceton - Raphael Road	Line	BGE	($2.4)	($1.3)	($0.0)	($1.1)	$0.2	$0.1	$0.0	$0.1	($1.0)	215	112
10	Cloverdale - Lexington	Line	AEP	$1.6	$0.7	$0.0	$0.9	$0.1	($0.1)	($0.0)	$0.1	$1.0	1,044	620
11	Atlantic - Larrabee	Line	JCPL	$0.9	$0.1	$0.0	$0.9	$0.0	($0.1)	($0.0)	$0.1	$0.9	123	12
12	Bedington - Black Oak	Interface	500	$1.5	$0.8	$0.1	$0.8	($0.0)	($0.0)	($0.0)	$0.0	$0.8	1,819	47
13	Brunner Island - Yorkana	Line	Met-Ed	($2.0)	($1.1)	($0.0)	($0.9)	$0.3	$0.1	$0.0	$0.2	($0.7)	219	168
14	Wylie Ridge	Transformer	AP	$1.2	$0.6	$0.0	$0.5	($0.0)	($0.1)	($0.0)	$0.1	$0.6	479	376
15	Kingwood - Pruntytown	Line	AP	$1.1	$0.6	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	421	49
27	Sayreville - Werner	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.3	$0.3	0	4
31	Franklin - West Wharton	Line	JCPL	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	57	0
36	Kilmer - Sayreville	Line	JCPL	$0.5	$0.3	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	117	0
194	Montville - Roseland	Line	JCPL	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	5
225	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 September 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	$0.1	($0.2)	($0.0)	$0.2	$6.0	391	85
2	5004/5005 Interface	Interface	500	$8.2	$3.5	$0.0	$4.7	$0.2	($0.9)	($0.0)	$1.1	$5.7	643	241
3	Kammer	Transformer	500	$8.2	$3.5	$0.0	$4.8	$0.1	($0.6)	($0.0)	$0.7	$5.4	3,674	1,328
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	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.0	$1.3	($0.1)	$1.6	($0.0)	($0.2)	$0.0	$0.2	$1.7	2,888	907
6	Atlantic - Larrabee	Line	JCPL	$1.8	$0.4	$0.0	$1.5	($0.6)	($0.5)	($0.0)	($0.1)	$1.3	188	45
7	Athenia - Saddlebrook	Line	PSEG	($1.4)	($0.3)	($0.0)	($1.0)	($0.0)	$0.1	$0.0	($0.1)	($1.1)	1,094	139
8	Sammis - Wylie Ridge	Line	AP	$1.4	$0.5	$0.0	$0.9	$0.0	($0.0)	($0.0)	$0.0	$0.9	632	140
9	Graceton - Raphael Road	Line	BGE	($1.9)	($1.0)	($0.0)	($0.9)	$0.4	$0.2	$0.0	$0.2	($0.8)	300	127
10	East Frankfort - Crete	Line	ComEd	$1.3	$0.5	($0.0)	$0.7	($0.0)	($0.0)	$0.0	$0.0	$0.8	1,490	219
11	Cloverdale - Lexington	Line	AEP	$0.9	$0.3	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	752	335
12	Tiltonsville - Windsor	Line	AP	$1.2	$0.6	$0.0	$0.6	($0.0)	($0.0)	($0.0)	$0.0	$0.6	1,258	237
13	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
14	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.7	$0.3	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.5	732	190
15	Leonia - New Milford	Line	PSEG	($0.6)	($0.2)	($0.0)	($0.4)	($0.0)	$0.0	$0.0	($0.0)	($0.4)	3,088	39
38	Redoak - Sayreville	Line	JCPL	($0.0)	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	59	7
66	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
72	Kilmer - Sayreville	Line	JCPL	$0.4	$0.2	$0.0	$0.2	($0.0)	$0.2	$0.0	($0.2)	$0.0	0	11
74	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
87	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 September 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	Brunner Island - Yorkana	Line	Met-Ed	$1.9	($4.1)	$0.1	$6.1	($0.0)	$0.2	($0.0)	($0.2)	$5.9	219	168
2	Hunterstown	Transformer	Met-Ed	$4.1	($0.7)	$0.1	$4.8	$0.0	$0.0	($0.0)	($0.0)	$4.8	311	26
3	Doubs	Transformer	AP	$3.1	$2.0	$0.1	$1.2	($0.0)	($0.1)	($0.2)	($0.2)	$1.0	806	431
4	West	Interface	500	$4.2	$5.4	$0.0	($1.1)	$0.0	($0.1)	($0.0)	$0.1	($1.1)	159	58
5	AP South	Interface	500	$4.9	$4.0	$0.1	$1.0	($0.1)	($0.1)	($0.2)	($0.2)	$0.8	3,512	1,251
6	Jackson - TMI	Line	Met-Ed	$0.5	($0.6)	$0.1	$1.2	($0.1)	$0.3	($0.0)	($0.4)	$0.8	37	54
7	5004/5005 Interface	Interface	500	$10.8	$10.3	$0.0	$0.5	($0.3)	($0.7)	($0.1)	$0.3	$0.7	1,379	561
8	Graceton - Raphael Road	Line	BGE	($1.7)	($2.4)	($0.0)	$0.7	$0.1	$0.2	$0.1	($0.0)	$0.7	215	112
9	Middletown Jct	Transformer	Met-Ed	$0.6	($0.1)	$0.0	$0.7	($0.1)	$0.1	$0.0	($0.1)	$0.6	11	12
10	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.6	$0.1	$0.0	$0.6	($0.0)	$0.0	$0.0	($0.0)	$0.5	190	12
11	Brandon Shores - Riverside	Line	BGE	$3.3	$3.8	$0.0	($0.5)	($0.0)	($0.1)	($0.0)	$0.0	($0.5)	343	162
12	Collins - Middletown Jct	Line	Met-Ed	$0.3	($0.3)	$0.0	$0.6	($0.0)	$0.1	($0.0)	($0.1)	$0.5	169	39
13	Cloverdale - Lexington	Line	AEP	$1.3	$1.7	$0.0	($0.3)	$0.0	$0.1	($0.0)	($0.1)	($0.4)	1,044	620
14	Wylie Ridge	Transformer	AP	$0.7	$1.0	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	($0.1)	($0.4)	479	376
15	Millville - Old Chapel	Line	AP	$1.0	$1.1	$0.1	($0.0)	($0.1)	($0.0)	($0.2)	($0.3)	($0.4)	178	121
40	Cly - Collins	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	19	0
58	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
66	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
84	Carlisle Pike - Gardners	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0
108	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 September 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	Kammer	Transformer	500	$6.0	$7.9	$0.1	($1.8)	($0.0)	($0.3)	($0.1)	$0.2	($1.6)	3,674	1,328
2	Brunner Island - Yorkana	Line	Met-Ed	$0.3	($0.7)	$0.0	$1.0	$0.0	$0.0	($0.0)	$0.0	$1.0	86	27
3	5004/5005 Interface	Interface	500	$5.1	$6.0	$0.0	($0.9)	($0.1)	($0.3)	($0.0)	$0.1	($0.8)	643	241
4	Graceton - Raphael Road	Line	BGE	($1.4)	($2.2)	($0.0)	$0.8	$0.1	$0.3	$0.0	($0.2)	$0.6	300	127
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.0	$2.5	$0.0	($0.6)	($0.0)	($0.0)	($0.0)	$0.0	($0.6)	2,888	907
6	Hunterstown	Transformer	Met-Ed	$0.3	($0.1)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	($0.0)	$0.4	53	1
7	Tiltonsville - Windsor	Line	AP	$0.8	$1.2	$0.0	($0.4)	$0.0	($0.1)	($0.0)	$0.1	($0.3)	1,258	237
8	AP South	Interface	500	$2.0	$1.7	$0.0	$0.3	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	2,559	423
9	Wylie Ridge	Transformer	AP	$3.1	$2.8	$0.0	$0.3	($0.1)	($0.2)	($0.0)	$0.0	$0.3	354	335
10	East Frankfort - Crete	Line	ComEd	$0.8	$1.0	$0.0	($0.2)	$0.0	($0.0)	($0.0)	($0.0)	($0.2)	1,490	219
11	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.5	$0.6	$0.0	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	($0.2)	732	190
12	Hummelstown - Middletown Jct	Line	Met-Ed	$0.1	$0.3	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.2)	51	14
13	West	Interface	500	$6.9	$6.8	$0.0	$0.1	($0.0)	($0.1)	($0.0)	$0.1	$0.2	391	85
14	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.2	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	28	2
15	Cloverdale - Lexington	Line	AEP	$0.7	$0.9	$0.0	($0.2)	($0.0)	($0.0)	($0.0)	($0.0)	($0.2)	752	335
16	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
33	Collins - Middletown Jct	Line	Met-Ed	$0.1	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.1)	$0.1	101	16
35	Ironwood - South Lebanon	Line	Met-Ed	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	19	0
42	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
139	Germantown	Transformer	Met-Ed	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	10	0

PECO Control Zone

Table 7-29 PECO Control Zone top congestion cost impacts (By facility): January through September 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	5004/5005 Interface	Interface	500	$13.4	$19.9	$0.0	($6.5)	($0.5)	$1.4	($0.1)	($2.0)	($8.5)	1,379	561
2	Eddystone - Island Road	Line	PECO	$3.8	($4.4)	($0.0)	$8.1	($0.0)	$0.0	$0.0	($0.0)	$8.1	186	3
3	Limerick	Transformer	PECO	$3.1	$0.7	$0.0	$2.4	$0.1	($3.8)	($0.0)	$3.8	$6.3	53	18
4	AP South	Interface	500	$3.2	$7.9	$0.1	($4.6)	($0.1)	$0.2	($0.0)	($0.4)	($4.9)	3,512	1,251
5	West	Interface	500	$4.8	$7.2	$0.0	($2.3)	($0.0)	($0.0)	($0.0)	($0.0)	($2.4)	159	58
6	Bedington - Black Oak	Interface	500	$2.5	$4.5	$0.0	($1.9)	$0.0	$0.0	($0.0)	($0.0)	($2.0)	1,819	47
7	Graceton - Raphael Road	Line	BGE	($1.6)	($3.1)	($0.0)	$1.5	$0.3	$0.4	$0.0	($0.2)	$1.3	215	112
8	Peachbottom	Transformer	PECO	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.1	($0.4)	($1.2)	($1.2)	0	14
9	Doubs	Transformer	AP	$1.0	$2.0	$0.0	($1.0)	($0.3)	($0.2)	($0.0)	($0.2)	($1.2)	806	431
10	East	Interface	500	$1.5	$0.5	($0.0)	$1.0	($0.0)	$0.0	$0.0	($0.0)	$1.0	154	1
11	Tiltonsville - Windsor	Line	AP	$1.5	$2.3	$0.0	($0.8)	($0.1)	($0.0)	($0.0)	($0.1)	($0.9)	1,954	410
12	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
13	Keeney At5n	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.5	($0.0)	($0.9)	($0.9)	0	13
14	East Frankfort - Crete	Line	ComEd	$2.1	$3.0	($0.0)	($0.9)	($0.1)	($0.1)	$0.0	$0.0	($0.8)	2,242	797
15	Brandon Shores - Riverside	Line	BGE	$4.5	$4.9	$0.0	($0.4)	($0.2)	$0.2	($0.0)	($0.4)	($0.8)	343	162
20	Burlington - Croydon	Line	PECO	($0.2)	($0.6)	($0.0)	$0.4	$0.0	($0.1)	($0.0)	$0.1	$0.4	1,034	33
32	Jenkintown - Tabor	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	$0.0	($0.3)	($0.3)	0	10
49	Eddystone - Saville	Line	PECO	$0.1	($0.1)	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	60	39
50	Bradford - Planebrook	Line	PECO	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.1	$0.1	0	1
52	Bryn Mawr - Plymouth Meeting	Line	PECO	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0

Table 7-30 PECO Control Zone top congestion cost impacts (By facility): January through September 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	$3.7	$9.8	$0.0	($6.0)	($0.2)	($0.0)	$0.0	($0.2)	($6.2)	3,674	1,328
2	West	Interface	500	$3.0	$6.2	$0.0	($3.1)	($0.0)	($0.1)	($0.0)	$0.0	($3.1)	391	85
3	AP South	Interface	500	$0.6	$3.2	$0.0	($2.6)	($0.0)	$0.0	$0.0	($0.1)	($2.7)	2,559	423
4	5004/5005 Interface	Interface	500	$4.3	$6.6	$0.0	($2.3)	$0.0	($0.0)	$0.0	$0.0	($2.3)	643	241
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.5	$3.5	($0.0)	($2.0)	($0.1)	$0.1	($0.0)	($0.1)	($2.1)	2,888	907
6	Graceton - Raphael Road	Line	BGE	($0.9)	($2.9)	($0.0)	$2.0	$0.5	$0.6	($0.0)	($0.1)	$1.9	300	127
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	$1.3	($0.0)	($0.8)	($0.0)	$0.0	($0.0)	($0.0)	($0.9)	1,490	219
9	Tiltonsville - Windsor	Line	AP	$0.6	$1.5	$0.0	($0.9)	($0.0)	($0.1)	$0.0	$0.0	($0.9)	1,258	237
10	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.2	$1.0	($0.0)	($0.7)	($0.0)	$0.0	($0.0)	($0.1)	($0.8)	732	190
11	Sammis - Wylie Ridge	Line	AP	$0.5	$1.1	$0.0	($0.7)	($0.0)	$0.0	($0.0)	($0.1)	($0.7)	632	140
12	Cloverdale - Lexington	Line	AEP	$0.4	$1.1	$0.0	($0.7)	($0.0)	($0.0)	($0.0)	$0.0	($0.7)	752	335
13	Mount Storm - Pruntytown	Line	AP	$0.1	$0.5	$0.0	($0.5)	($0.0)	$0.0	($0.0)	($0.0)	($0.5)	525	132
14	Holmesburg - Richmond	Line	PECO	($0.2)	($0.5)	($0.0)	$0.3	($0.0)	($0.1)	$0.0	$0.1	$0.5	311	10
15	Bedington - Black Oak	Interface	500	$0.2	$0.6	$0.0	($0.4)	($0.0)	($0.0)	$0.0	$0.0	($0.4)	395	61
16	Burlington - Croydon	Line	PECO	($0.3)	($0.7)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	$0.0	$0.4	2,420	3
19	Emilie	Transformer	PECO	$0.3	($1.9)	($0.0)	$2.2	($0.2)	$1.7	$0.0	($1.9)	$0.3	281	247
23	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
33	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
42	Graceton - Peach Bottom	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.1	$0.1	0	16

PENELEC Control Zone

Table 7-31 PENELEC Control Zone top congestion cost impacts (By facility): January through September 2010 (See 2009 SOM, Table 7-31)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($45.1)	($68.5)	($0.0)	$23.4	$7.5	$2.3	$0.1	$5.3	$28.7	3,512	1,251
2	5004/5005 Interface	Interface	500	($10.8)	($35.5)	($0.1)	$24.6	$4.4	$2.2	$0.1	$2.3	$27.0	1,379	561
3	Bedington - Black Oak	Interface	500	($15.5)	($23.4)	($0.0)	$7.9	$0.4	$0.0	$0.0	$0.4	$8.2	1,819	47
4	West	Interface	500	($3.6)	($8.6)	$0.0	$5.1	$0.3	$0.2	$0.0	$0.1	$5.1	159	58
5	Mount Storm - Pruntytown	Line	AP	($3.4)	($5.6)	$0.0	$2.2	$3.5	$0.9	$0.0	$2.7	$4.9	571	574
6	Seward	Transformer	PENELEC	$11.9	$7.1	$0.0	$4.8	($0.2)	$0.5	($0.0)	($0.8)	$4.0	371	63
7	Bear Rock - Johnstown	Line	PENELEC	($2.1)	($4.1)	($0.0)	$1.9	$1.1	$0.0	$0.0	$1.1	$3.0	197	57
8	Wylie Ridge	Transformer	AP	$0.9	$3.1	$0.1	($2.2)	($0.7)	($0.0)	($0.1)	($0.8)	($3.0)	479	376
9	Altoona - Bear Rock	Line	PENELEC	($2.4)	($4.8)	($0.0)	$2.3	$0.6	$0.1	$0.0	$0.5	$2.9	248	55
10	Tiltonsville - Windsor	Line	AP	$3.3	$4.4	$0.0	($1.1)	($1.0)	$0.0	($0.0)	($1.0)	($2.2)	1,954	410
11	AEP-DOM	Interface	500	($4.4)	($6.3)	($0.0)	$1.8	$0.2	($0.1)	$0.0	$0.3	$2.1	471	89
12	East Frankfort - Crete	Line	ComEd	$4.3	$5.7	$0.0	($1.4)	($0.8)	($0.0)	($0.0)	($0.7)	($2.1)	2,242	797
13	Johnstown - Seward	Line	PENELEC	$2.7	$0.7	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	52	0
14	Hunterstown	Transformer	Met-Ed	($0.8)	($2.5)	($0.0)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.7	311	26
15	Doubs	Transformer	AP	($2.2)	($3.2)	$0.0	$1.0	$0.6	($0.1)	($0.0)	$0.6	$1.6	806	431
17	Homer City - Seward	Line	PENELEC	$4.6	$3.3	$0.0	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	83	0
23	Keystone - Shelocta	Line	PENELEC	$3.0	$2.0	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	39	0
27	Blairsville - Shelocta	Line	PENELEC	$1.7	$1.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	24	0
28	Roxbury - Shade Gap	Line	PENELEC	($0.8)	($0.7)	($0.0)	($0.0)	$0.9	$1.5	$0.0	($0.6)	($0.6)	32	96
34	Clarks Summit - Eclipse	Line	PENELEC	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	64	0

Table 7-32 PENELEC Control Zone top congestion cost impacts (By facility): January through September 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	AP South	Interface	500	($12.2)	($25.8)	($0.0)	$13.6	$0.8	$0.3	$0.1	$0.5	$14.1	2,559	423
2	West	Interface	500	($2.2)	($15.2)	($0.0)	$13.0	$0.0	$0.1	$0.0	($0.0)	$13.0	391	85
3	5004/5005 Interface	Interface	500	($2.9)	($15.5)	($0.0)	$12.6	$0.4	$1.6	$0.1	($1.1)	$11.4	643	241
4	Kammer	Transformer	500	$4.8	$15.9	$0.2	($10.8)	($0.5)	($0.9)	($0.1)	$0.2	($10.6)	3,674	1,328
5	Wylie Ridge	Transformer	AP	$1.5	$10.3	$0.1	($8.8)	($0.6)	($0.7)	($0.0)	$0.1	($8.7)	354	335
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$4.0	$7.5	($0.0)	($3.5)	$0.2	($0.5)	$0.0	$0.6	($2.9)	2,888	907
7	Seward	Transformer	PENELEC	$6.5	$3.7	($0.0)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	218	0
8	Mount Storm - Pruntytown	Line	AP	($2.4)	($4.6)	($0.0)	$2.2	$0.3	($0.1)	$0.0	$0.5	$2.7	525	132
9	Sammis - Wylie Ridge	Line	AP	$1.0	$3.8	$0.1	($2.7)	($0.1)	($0.1)	$0.0	($0.0)	($2.7)	632	140
10	Tiltonsville - Windsor	Line	AP	$1.0	$2.9	$0.0	($1.9)	$0.1	($0.0)	($0.0)	$0.1	($1.9)	1,258	237
11	Bedington - Black Oak	Interface	500	($1.5)	($3.0)	($0.0)	$1.6	($0.0)	$0.0	$0.0	($0.0)	$1.5	395	61
12	East Frankfort - Crete	Line	ComEd	$1.6	$3.0	$0.0	($1.3)	$0.0	($0.0)	($0.0)	$0.0	($1.3)	1,490	219
13	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
14	Homer City - Shelocta	Line	PENELEC	($3.2)	($4.6)	($0.1)	$1.3	($0.1)	$0.1	$0.0	($0.1)	$1.2	340	80
15	Altoona - Bear Rock	Line	PENELEC	($1.9)	($3.0)	($0.0)	$1.1	($0.1)	($0.1)	$0.0	($0.1)	$1.1	176	32
16	Homer City	Transformer	PENELEC	$1.2	$0.2	($0.0)	$1.0	($0.0)	$0.0	$0.0	($0.0)	$1.0	248	2
25	Keystone - Shelocta	Line	PENELEC	($0.4)	($0.8)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	103	43
26	Altoona - Raystown	Line	PENELEC	($0.8)	($1.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	54	0
28	Bear Rock - Johnstown	Line	PENELEC	($0.5)	($0.7)	($0.0)	$0.2	($0.1)	($0.1)	$0.0	($0.0)	$0.2	80	45
30	Clarks Summit - Eclipse	Line	PENELEC	$0.1	($0.1)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	18	2

Pepco Control Zone

Table 7-33 Pepco Control Zone top congestion cost impacts (By facility): January through September 2010 (See 2009 SOM, Table 7-33)

				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	$106.0	$78.5	$1.8	$29.3	($5.2)	($3.3)	($1.6)	($3.6)	$25.7	3,512	1,251
2	Bedington - Black Oak	Interface	500	$39.4	$27.8	$0.8	$12.4	($0.5)	($0.6)	($0.3)	($0.1)	$12.2	1,819	47
3	Doubs	Transformer	AP	$38.8	$24.6	$0.7	$14.9	($4.0)	$1.2	($1.7)	($6.8)	$8.1	806	431
4	Cloverdale - Lexington	Line	AEP	$10.7	$7.6	$0.1	$3.2	($1.1)	($1.1)	($0.3)	($0.3)	$2.9	1,044	620
5	Brandon Shores - Riverside	Line	BGE	($13.6)	($10.2)	($0.2)	($3.5)	$1.2	$0.5	$0.3	$1.1	($2.4)	343	162
6	5004/5005 Interface	Interface	500	$6.8	$4.6	$0.2	$2.4	($0.3)	($0.1)	($0.1)	($0.3)	$2.0	1,379	561
7	Reid - Ringgold	Line	AP	$4.6	$2.8	$0.1	$2.0	($0.0)	($0.1)	($0.0)	$0.0	$2.0	271	25
8	Mount Storm - Pruntytown	Line	AP	$9.4	$6.7	$0.1	$2.7	($2.5)	($2.1)	($0.5)	($0.9)	$1.9	571	574
9	West	Interface	500	$5.9	$3.9	$0.0	$2.0	($0.2)	($0.1)	($0.0)	($0.1)	$1.8	159	58
10	East Frankfort - Crete	Line	ComEd	$4.9	$3.0	$0.0	$1.9	($0.4)	($0.3)	($0.0)	($0.2)	$1.7	2,242	797
11	Graceton - Raphael Road	Line	BGE	$5.6	$3.8	$0.2	$2.0	($0.6)	($0.4)	($0.2)	($0.3)	$1.7	215	112
12	AEP-DOM	Interface	500	$8.0	$6.6	$0.1	$1.5	($0.1)	($0.2)	($0.1)	($0.0)	$1.5	471	89
13	Bowie	Transformer	Pepco	$2.3	$1.1	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	44	0
14	Bowie - Lanham	Line	Pepco	$2.2	$0.9	$0.1	$1.4	($0.3)	($0.2)	($0.1)	($0.2)	$1.1	36	13
15	Tiltonsville - Windsor	Line	AP	$4.3	$2.9	$0.1	$1.5	($0.4)	($0.1)	($0.1)	($0.4)	$1.1	1,954	410
23	Benning - Ritchie	Line	Pepco	$0.8	$0.2	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	78	0
29	Buzzard - Ritchie	Line	Pepco	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	58	1
47	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
57	Burtonsville - Sandy Springs	Line	Pepco	($0.3)	($0.2)	($0.0)	($0.1)	$0.4	$0.2	$0.0	$0.2	$0.2	20	41
68	Pumphrey	Transformer	Pepco	($0.3)	($0.2)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	56	0

Table 7-34 Pepco Control Zone top congestion cost impacts (By facility): January through September 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	$41.9	$31.6	$0.7	$11.0	($1.3)	($3.0)	($0.6)	$1.1	$12.1	2,559	423
2	Kammer	Transformer	500	$21.9	$15.1	$0.3	$7.1	($1.1)	($2.0)	($0.4)	$0.5	$7.6	3,674	1,328
3	Buzzard - Ritchie	Line	Pepco	$25.3	$3.2	$0.2	$22.3	($13.9)	$1.9	($0.6)	($16.4)	$5.9	409	149
4	Mount Storm - Pruntytown	Line	AP	$7.5	$5.8	$0.1	$1.9	($0.2)	($0.8)	($0.1)	$0.5	$2.4	525	132
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$6.2	$4.1	($0.0)	$2.0	($0.2)	($0.5)	$0.0	$0.3	$2.3	2,888	907
6	West	Interface	500	$8.1	$6.0	$0.0	$2.1	($0.1)	($0.1)	($0.0)	$0.0	$2.2	391	85
7	Graceton - Raphael Road	Line	BGE	$4.5	$3.1	$0.2	$1.5	($0.6)	($1.0)	($0.2)	$0.3	$1.8	300	127
8	Bedington - Black Oak	Interface	500	$5.8	$4.2	$0.1	$1.6	($0.0)	($0.1)	($0.0)	$0.1	$1.7	395	61
9	Wylie Ridge	Transformer	AP	$6.2	$4.9	$0.0	$1.3	($0.3)	($0.7)	($0.0)	$0.3	$1.7	354	335
10	Cloverdale - Lexington	Line	AEP	$5.3	$3.9	$0.1	$1.5	($0.2)	($0.4)	($0.1)	$0.1	$1.6	752	335
11	East Frankfort - Crete	Line	ComEd	$2.4	$1.6	$0.0	$0.7	$0.0	($0.1)	($0.0)	$0.1	$0.8	1,490	219
12	Sammis - Wylie Ridge	Line	AP	$2.4	$1.7	$0.0	$0.8	($0.1)	($0.2)	($0.0)	($0.0)	$0.8	632	140
13	Mount Storm	Transformer	AP	$1.7	$1.3	$0.0	$0.5	$0.0	($0.3)	($0.1)	$0.2	$0.7	123	70
14	Tiltonsville - Windsor	Line	AP	$1.7	$1.1	$0.1	$0.7	($0.0)	($0.1)	($0.1)	($0.0)	$0.7	1,258	237
15	5004/5005 Interface	Interface	500	$1.9	$1.3	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.1	$0.7	643	241
17	Alabama Ave. - Palmers Corner	Line	Pepco	$0.5	$0.0	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	12	0
20	Brighton	Transformer	Pepco	$0.7	$0.4	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	43	1
21	Dickerson - Pleasant View	Line	Pepco	$0.7	$0.5	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	40	13
30	Burtonsville - Oak Grove	Line	Pepco	($0.3)	($0.4)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	29	0
39	Oak Grove - Ritchie	Line	Pepco	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.1	$0.1	0	6

PPL Control Zone

Table 7-35 PPL Control Zone top congestion cost impacts (By facility): January through September 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	$32.9	$42.5	$0.9	($8.7)	$2.9	$1.3	($0.4)	$1.1	($7.6)	1,379	561
2	Brunner Island - Yorkana	Line	Met-Ed	($5.2)	($9.3)	($0.1)	$4.0	$0.3	$0.2	$0.1	$0.1	$4.2	219	168
3	West	Interface	500	$9.4	$12.2	$0.2	($2.7)	$0.1	$0.2	($0.1)	($0.2)	($2.8)	159	58
4	AP South	Interface	500	$2.8	$2.0	$0.5	$1.3	$0.3	($0.0)	($0.1)	$0.3	$1.6	3,512	1,251
5	East Frankfort - Crete	Line	ComEd	$3.5	$4.9	($0.0)	($1.4)	$0.2	($0.1)	$0.0	$0.3	($1.1)	2,242	797
6	Harwood - Siegfried	Line	PPL	($0.2)	($1.7)	$0.0	$1.5	($0.3)	$2.2	($0.1)	($2.6)	($1.1)	92	117
7	Graceton - Raphael Road	Line	BGE	($3.6)	($4.8)	($0.1)	$1.1	($0.0)	$0.1	$0.0	($0.0)	$1.1	215	112
8	Harwood - Susquehanna	Line	PPL	$0.2	($1.0)	$0.0	$1.3	$0.3	$0.5	($0.1)	($0.3)	$1.0	51	22
9	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.7	$0.2	$0.4	$0.9	$0.9	0	27
10	Eldred - Sunbury	Line	PPL	$0.6	($0.1)	$0.0	$0.7	$0.1	($0.1)	($0.0)	$0.1	$0.8	50	33
11	Susquehanna	Transformer	PPL	$1.0	$0.3	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	39	0
12	Tiltonsville - Windsor	Line	AP	$2.9	$3.9	$0.1	($0.9)	$0.4	$0.2	($0.0)	$0.2	($0.7)	1,954	410
13	East Palmerton - Siegfried	Line	PPL	($0.1)	($0.7)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	70	0
14	Cloverdale - Lexington	Line	AEP	$2.5	$3.6	$0.1	($1.0)	$0.3	($0.0)	$0.0	$0.4	($0.6)	1,044	620
15	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.6	$2.4	($0.0)	($0.8)	$0.1	($0.1)	$0.0	$0.2	($0.6)	800	245
17	East Palmerton - Harwood	Line	PPL	($0.0)	($0.5)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	51	0
24	Frackville - Siegfried	Line	PPL	($0.1)	($0.5)	$0.0	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	34	7
28	Eldred - Frackville	Line	PPL	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	20	0
32	Martins Creek - Siegfried	Line	PPL	($0.0)	($0.1)	$0.0	$0.0	($0.0)	$0.2	($0.1)	($0.3)	($0.3)	9	17
41	Juniata	Transformer	PPL	$0.5	$0.4	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	11	0

Table 7-36 PPL Control Zone top congestion cost impacts (By facility): January through September 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	$1.7	$5.5	$0.6	($3.2)	($0.2)	($0.2)	($0.1)	($0.0)	($3.2)	3,674	1,328
2	5004/5005 Interface	Interface	500	$2.3	$5.7	$0.4	($2.9)	$0.1	($0.8)	($0.1)	$0.8	($2.2)	643	241
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.6	$2.3	($0.1)	($1.8)	($0.2)	($0.2)	$0.0	$0.0	($1.8)	2,888	907
4	AP South	Interface	500	$0.5	($0.2)	$0.2	$0.9	$0.1	($0.1)	$0.1	$0.2	$1.1	2,559	423
5	Hummelstown - Middletown Jct	Line	Met-Ed	$1.0	($0.0)	$0.0	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.1	51	14
6	Graceton - Raphael Road	Line	BGE	($0.5)	($1.5)	($0.0)	$1.0	$0.1	$0.0	$0.0	$0.1	$1.1	300	127
7	Brunner Island - Yorkana	Line	Met-Ed	($0.0)	($0.9)	($0.0)	$0.8	$0.0	$0.1	($0.0)	($0.0)	$0.8	86	27
8	West	Interface	500	$2.8	$4.1	$0.5	($0.8)	($0.0)	($0.2)	($0.0)	$0.1	($0.6)	391	85
9	Harwood - Susquehanna	Line	PPL	$0.1	($0.4)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	13	0
10	Sammis - Wylie Ridge	Line	AP	$0.1	$0.7	$0.1	($0.5)	$0.0	($0.0)	$0.0	$0.0	($0.5)	632	140
11	East Frankfort - Crete	Line	ComEd	$0.2	$0.6	$0.0	($0.3)	($0.0)	($0.0)	$0.0	$0.0	($0.3)	1,490	219
12	Wylie Ridge	Transformer	AP	$1.1	$1.8	$0.3	($0.4)	$0.2	$0.1	$0.0	$0.1	($0.3)	354	335
13	PL North	Interface	PPL	$0.0	$0.0	$0.0	$0.0	$0.4	$0.6	($0.0)	($0.3)	($0.3)	0	176
14	Mount Storm - Pruntytown	Line	AP	$0.1	($0.1)	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	525	132
15	Atlantic - Larrabee	Line	JCPL	$0.0	$0.1	$0.0	($0.1)	($0.1)	$0.1	$0.0	($0.2)	($0.3)	188	45
22	Jenkins - Susquehanna	Line	PPL	$0.1	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	9	0
39	Dauphin - Juniata	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0
45	Eldred - Sunbury	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
138	Eldred - Frackville	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
162	Harwood	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	1	1

PSEG Control Zone

Table 7-37 PSEG Control Zone top congestion cost impacts (By facility): January through September 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	$8.9	$1.2	$0.6	$8.3	($0.1)	$0.8	($0.5)	($1.4)	$6.9	1,210	184
2	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.7)	$1.1	($1.7)	($3.4)	($3.4)	454	39
3	Athenia - Saddlebrook	Line	PSEG	$12.5	$2.5	$7.5	$17.6	($6.8)	$2.5	($5.0)	($14.3)	$3.3	2,947	331
4	AP South	Interface	500	$1.0	$5.4	$2.4	($1.9)	$0.2	($0.3)	($1.5)	($1.0)	($2.9)	3,512	1,251
5	Eddystone - Island Road	Line	PECO	$1.0	($0.7)	$0.0	$1.7	$0.0	$0.0	($0.0)	$0.0	$1.7	186	3
6	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
7	5004/5005 Interface	Interface	500	$24.1	$23.0	$2.0	$3.0	$1.9	$1.7	($1.8)	($1.6)	$1.5	1,379	561
8	Redoak - Sayreville	Line	JCPL	$1.2	($0.2)	$0.0	$1.4	$0.0	($0.0)	($0.0)	($0.0)	$1.4	795	57
9	North Ave - Pvsc	Line	PSEG	$0.2	($0.8)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	656	0
10	Brandon Shores - Riverside	Line	BGE	$5.8	$5.0	$0.3	$1.0	$0.4	$0.1	($0.3)	($0.0)	$1.0	343	162
11	Bedington - Black Oak	Interface	500	$1.8	$3.5	$0.9	($0.8)	($0.0)	($0.0)	($0.1)	($0.1)	($0.9)	1,819	47
12	Bayway - Federal Square	Line	PSEG	$0.6	($0.4)	$0.0	$1.0	($0.0)	$0.0	($0.0)	($0.0)	$0.9	519	8
13	Hillsdale - New Milford	Line	PSEG	$0.5	$0.2	$0.7	$1.0	$0.0	$0.0	($0.0)	($0.0)	$0.9	248	6
14	Doubs	Transformer	AP	$1.4	$1.2	$0.2	$0.4	($0.3)	$0.4	($0.6)	($1.2)	($0.8)	806	431
15	Graceton - Raphael Road	Line	BGE	($3.4)	($3.6)	($0.2)	($0.0)	$0.3	($0.2)	$0.3	$0.8	$0.8	215	112
17	Bergen - Hoboken	Line	PSEG	$0.1	($0.2)	$0.3	$0.7	($0.2)	($0.1)	$0.1	$0.1	$0.7	471	29
20	Leonia - New Milford	Line	PSEG	$0.3	$0.2	$0.7	$0.8	($0.0)	$0.1	($0.0)	($0.2)	$0.7	1,028	6
21	Bayonne - PVSC	Line	PSEG	$0.0	($0.5)	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	579	0
25	Hudson - Marion	Line	PSEG	$0.3	$0.1	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	170	0
28	Fairlawn - Saddlebrook	Line	PSEG	$0.4	$0.2	$0.7	$0.9	($0.0)	$0.1	($0.4)	($0.5)	$0.4	492	17

Table 7-38 PSEG Control Zone top congestion cost impacts (By facility): January through September 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	Leonia - New Milford	Line	PSEG	$1.9	$0.7	$2.8	$4.1	($0.0)	$0.0	($0.3)	($0.3)	$3.8	3,088	39
2	Athenia - Saddlebrook	Line	PSEG	$3.2	$0.5	$1.3	$4.0	($0.2)	$0.1	($0.5)	($0.8)	$3.1	1,094	139
3	Plainsboro - Trenton	Line	PSEG	$3.5	($0.1)	$0.1	$3.8	($0.3)	$0.4	($0.1)	($0.7)	$3.1	389	164
4	Cedar Grove - Clifton	Line	PSEG	$1.7	$0.4	$0.7	$2.0	($0.0)	($0.0)	($0.1)	($0.1)	$1.9	775	30
5	AP South	Interface	500	$0.6	$3.1	$0.8	($1.6)	$0.0	($0.1)	($0.3)	($0.2)	($1.8)	2,559	423
6	Fairlawn - Saddlebrook	Line	PSEG	$1.1	$0.2	$0.6	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	841	0
7	West	Interface	500	$10.9	$12.7	$0.8	($1.0)	($0.1)	$0.1	($0.2)	($0.3)	($1.3)	391	85
8	Wylie Ridge	Transformer	AP	$4.3	$5.4	$0.5	($0.6)	$0.0	$0.1	($0.6)	($0.7)	($1.3)	354	335
9	Monroe - New Freedom	Line	AECO	($0.1)	($1.1)	($0.0)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	584	0
10	Hillsdale - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.3	($0.4)	($0.8)	($0.8)	0	47
11	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
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	167	11
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)	62	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
17	Athenia - Fairlawn	Line	PSEG	$0.4	$0.0	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	165	6
19	Bayonne - PVSC	Line	PSEG	$0.0	($0.3)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	523	0
20	Sewaren	Transformer	PSEG	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	89	0
26	Branchburg - Readington	Line	PSEG	$0.2	($0.0)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	21	10

RECO Control Zone

Table 7-39 RECO Control Zone top congestion cost impacts (By facility): January through September 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	$0.9	$0.1	$0.0	$0.8	$0.2	($0.1)	($0.0)	$0.3	$1.1	1,379	561
2	Branchburg - Readington	Line	PSEG	$0.6	$0.0	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.6	1,210	184
3	West	Interface	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	159	58
4	Brandon Shores - Riverside	Line	BGE	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.3	343	162
5	AP South	Interface	500	($0.2)	($0.0)	$0.0	($0.2)	($0.0)	$0.0	($0.0)	($0.1)	($0.2)	3,512	1,251
6	Athenia - Saddlebrook	Line	PSEG	$0.2	$0.0	($0.0)	$0.2	$0.0	($0.1)	$0.0	$0.1	$0.2	2,947	331
7	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	1,954	410
8	Graceton - Raphael Road	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.2)	215	112
9	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	2,242	797
10	Brunner Island - Yorkana	Line	Met-Ed	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	219	168
11	Hawthorn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	454	39
12	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
13	Wylie Ridge	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	479	376
14	Cloverdale - Lexington	Line	AEP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	1,044	620
15	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	806	431

Table 7-40 RECO Control Zone top congestion cost impacts (By facility): January through September 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	85
2	Kammer	Transformer	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	3,674	1,328
3	5004/5005 Interface	Interface	500	$0.4	$0.0	$0.0	$0.4	($0.0)	($0.0)	($0.0)	($0.1)	$0.4	643	241
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.2	$0.0	($0.0)	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	2,888	907
5	Wylie Ridge	Transformer	AP	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	354	335
6	Athenia - Saddlebrook	Line	PSEG	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	1,094	139
7	Graceton - Raphael Road	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	300	127
8	AP South	Interface	500	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	2,559	423
9	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	1,490	219
10	Sammis - Wylie Ridge	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	632	140
11	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	1,258	237
12	Fairlawn - Saddlebrook	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	841	0
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	732	190
14	Elrama - Mitchell	Line	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	225	184
15	Cloverdale - Lexington	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.0	752	335

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-41 AEP Control Zone top congestion cost impacts (By facility): January through September 2010 (See 2009 SOM, Table 7-41)

				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	($32.6)	($81.8)	$0.3	$49.5	($3.2)	$2.6	$1.0	($4.7)	$44.8	3,512	1,251
2	AEP-DOM	Interface	500	$7.5	($20.1)	$1.0	$28.6	($0.2)	($0.3)	($0.3)	($0.1)	$28.4	471	89
3	Bedington - Black Oak	Interface	500	($12.2)	($26.6)	$0.0	$14.4	($0.1)	($0.0)	$0.0	($0.0)	$14.4	1,819	47
4	5004/5005 Interface	Interface	500	($17.9)	($27.3)	($0.4)	$9.0	($0.2)	$2.7	$0.7	($2.2)	$6.7	1,379	561
5	Baker - Broadford	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($1.5)	$1.0	($3.5)	($5.9)	($5.6)	10	74
6	Belmont	Transformer	AP	$3.7	($0.8)	$0.7	$5.3	$0.2	($0.1)	($0.5)	($0.2)	$5.1	1,057	109
7	Kanawha River	Transformer	AEP	$2.7	($0.5)	$0.5	$3.7	$0.0	($0.0)	($0.0)	$0.0	$3.7	190	11
8	Mount Storm - Pruntytown	Line	AP	($2.9)	($8.1)	($0.1)	$5.1	($0.6)	$1.7	$0.4	($1.8)	$3.3	571	574
9	Mahans Lane - Tidd	Line	AEP	($1.4)	($4.7)	($0.3)	$3.0	$0.3	$0.1	$0.0	$0.2	$3.2	646	207
10	Brues - West Bellaire	Line	AEP	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.8	($0.2)	($3.2)	($3.2)	0	78
11	West	Interface	500	($5.6)	($9.0)	($0.1)	$3.3	($0.2)	$0.3	$0.1	($0.4)	$2.9	159	58
12	Doubs	Transformer	AP	($10.6)	($13.7)	($0.2)	$2.8	$0.0	$0.9	$0.3	($0.5)	$2.3	806	431
13	Kanawha - Kincaid	Line	AEP	$1.4	($0.7)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	220	0
14	Electric Jct - Nelson	Line	ComEd	$0.3	$0.5	$5.6	$5.4	($0.1)	($0.0)	($7.3)	($7.3)	($2.0)	1,454	236
15	Culloden - Wyoming	Line	AEP	$0.6	($0.8)	$0.5	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	46	0
18	Kammer - Natrium	Line	AEP	$1.5	($0.4)	$0.2	$2.0	($0.3)	$0.1	($0.1)	($0.4)	$1.6	307	48
21	Sullivan	Transformer	AEP	($0.0)	($1.4)	($0.0)	$1.3	$0.0	$0.0	$0.0	($0.0)	$1.3	185	47
22	Cloverdale - Ivy Hill	Line	AEP	$0.0	$0.0	$0.0	$0.0	($1.1)	$0.1	$0.0	($1.2)	($1.2)	0	111
24	Ruth - Turner	Line	AEP	$0.7	($0.3)	$0.0	$1.0	($0.0)	($0.0)	($0.0)	($0.1)	$1.0	88	36
25	Big Sandy - Grangston	Line	AEP	$0.9	($0.0)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	344	0

Table 7-42 AEP Control Zone top congestion cost impacts (By facility): January through September 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	($16.5)	($29.0)	$1.0	$13.6	($0.7)	$0.4	$0.3	($0.9)	$12.7	2,559	423
2	Kammer	Transformer	500	($20.6)	($34.6)	($0.6)	$13.4	($0.8)	$2.5	$0.4	($2.9)	$10.6	3,674	1,328
3	Ruth - Turner	Line	AEP	$4.9	($1.6)	$0.5	$7.0	($1.2)	($0.4)	($0.1)	($0.9)	$6.1	704	279
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$17.4	$8.8	$1.1	$9.6	($2.6)	($1.1)	($2.4)	($3.9)	$5.8	2,888	907
5	Kanawha - Kincaid	Line	AEP	$2.8	($2.1)	$0.2	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	291	0
6	Kammer - Ormet	Line	AEP	$7.8	$1.1	$0.3	$6.9	($1.6)	$0.5	($0.1)	($2.2)	$4.7	552	509
7	Kanawha River	Transformer	AEP	$3.2	($0.3)	$0.5	$4.0	$0.1	($0.3)	($0.1)	$0.4	$4.3	161	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	($3.7)	($0.4)	$3.4	$0.0	$0.0	$0.0	$0.0	$3.4	511	2
10	Sammis - Wylie Ridge	Line	AP	($4.4)	($2.3)	($0.1)	($2.1)	($0.3)	$0.2	($0.0)	($0.5)	($2.6)	632	140
11	5004/5005 Interface	Interface	500	($8.0)	($10.7)	$0.0	$2.8	$0.2	$0.5	$0.1	($0.2)	$2.5	643	241
12	Mount Storm - Pruntytown	Line	AP	($3.1)	($5.2)	$0.2	$2.3	$0.0	$0.2	$0.1	($0.1)	$2.2	525	132
13	East Frankfort - Crete	Line	ComEd	$3.5	$2.0	$1.4	$2.9	($0.0)	$0.1	($0.7)	($0.9)	$2.0	1,490	219
14	Cloverdale - Lexington	Line	AEP	($6.3)	($4.5)	($0.4)	($2.1)	$0.5	$0.2	$0.1	$0.4	($1.8)	752	335
15	Belmont	Transformer	AP	$0.3	($1.4)	$0.3	$2.0	($0.0)	($0.1)	($0.2)	($0.2)	$1.8	871	71
19	Axton	Transformer	AEP	$0.3	($0.8)	$0.1	$1.2	($0.1)	$0.1	$0.0	($0.2)	$1.1	114	12
25	Poston - Postel Tap	Line	AEP	$0.4	($0.6)	$0.2	$1.2	$0.1	$0.5	($0.0)	($0.4)	$0.8	148	118
26	Marquis - Waverly	Line	AEP	$0.7	$0.0	$0.1	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.7	74	14
30	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
33	Muskingum River	Transformer	AEP	$0.1	($0.3)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0

AP Control Zone

Table 7-43 AP Control Zone top congestion cost impacts (By facility): January through September 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	($30.9)	($119.4)	($8.3)	$80.2	$4.6	$5.6	$7.3	$6.3	$86.6	3,512	1,251
2	Doubs	Transformer	AP	$13.9	($9.8)	($0.1)	$23.6	$3.3	$0.8	$0.1	$2.7	$26.3	806	431
3	Bedington - Black Oak	Interface	500	($10.2)	($37.9)	($1.8)	$25.9	$0.3	$0.4	$0.1	($0.0)	$25.9	1,819	47
4	Mount Storm - Pruntytown	Line	AP	($2.8)	($11.2)	($0.4)	$7.9	$2.3	$1.5	$1.9	$2.7	$10.6	571	574
5	Tiltonsville - Windsor	Line	AP	$14.5	$3.5	$1.4	$12.4	($2.2)	($0.6)	($1.6)	($3.2)	$9.2	1,954	410
6	5004/5005 Interface	Interface	500	($17.2)	($26.4)	($1.4)	$7.8	$2.0	$2.8	$1.5	$0.7	$8.4	1,379	561
7	Belmont	Transformer	AP	$7.2	($0.7)	$0.2	$8.1	($0.3)	($0.3)	($0.2)	($0.2)	$7.9	1,057	109
8	AEP-DOM	Interface	500	($2.1)	($7.8)	$0.4	$6.0	$0.3	($0.2)	($0.1)	$0.4	$6.4	471	89
9	Kingwood - Pruntytown	Line	AP	$5.1	$1.6	$0.6	$4.1	$0.0	($0.1)	($0.2)	($0.0)	$4.1	421	49
10	Cloverdale - Lexington	Line	AEP	$1.4	($3.4)	$0.9	$5.7	($0.1)	$0.4	($1.8)	($2.2)	$3.5	1,044	620
11	Endless Caverns	Transformer	Dominion	$2.6	$0.0	$0.3	$2.9	$0.0	$0.0	($0.0)	($0.0)	$2.9	541	3
12	Mahans Lane - Tidd	Line	AEP	$3.9	$1.4	$0.4	$2.9	($0.4)	($0.1)	($0.2)	($0.5)	$2.4	646	207
13	Nipetown - Reid	Line	AP	$0.0	($2.5)	($0.0)	$2.5	$0.1	$0.2	($0.0)	($0.1)	$2.4	296	63
14	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
15	Middlebourne - Willow	Line	AP	$2.0	($0.2)	$0.3	$2.5	($0.2)	($0.1)	($0.2)	($0.3)	$2.1	317	81
17	Wylie Ridge	Transformer	AP	$0.8	$1.4	$0.6	$0.0	($0.7)	($0.2)	($1.4)	($1.9)	($1.9)	479	376
18	Hamilton - Weirton	Line	AP	$2.8	$1.0	$0.2	$2.0	($0.1)	$0.1	($0.1)	($0.3)	$1.7	443	18
19	Yukon	Transformer	AP	$1.7	$0.1	$0.1	$1.7	$0.0	$0.1	$0.1	$0.0	$1.7	112	17
20	Halfway - Marlowe	Line	AP	$0.6	($0.7)	($0.0)	$1.3	$0.1	($0.1)	$0.0	$0.2	$1.5	60	20
21	Albright - Snowy Creek	Line	AP	$0.9	($0.3)	$0.0	$1.2	$0.0	($0.0)	($0.0)	$0.0	$1.3	252	4

Table 7-44 AP Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2009 SOM, Table 7-44)

				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	($12.7)	($50.5)	($3.9)	$33.9	$1.9	$1.7	$2.7	$2.9	$36.8	2,559	423
2	Kammer	Transformer	500	$17.8	$27.8	$6.8	($3.2)	($3.0)	($0.9)	($8.2)	($10.3)	($13.5)	3,674	1,328
3	Mount Storm - Pruntytown	Line	AP	($2.0)	($10.1)	($0.6)	$7.4	$0.8	$0.8	$0.5	$0.5	$7.9	525	132
4	Bedington - Black Oak	Interface	500	($1.3)	($6.1)	($0.2)	$4.6	($0.3)	$0.2	$0.4	($0.2)	$4.5	395	61
5	5004/5005 Interface	Interface	500	($8.4)	($12.1)	($1.2)	$2.5	$0.9	$0.8	$1.8	$1.9	$4.4	643	241
6	Tiltonsville - Windsor	Line	AP	$7.1	$2.2	$0.5	$5.4	($0.5)	($0.2)	($0.8)	($1.1)	$4.2	1,258	237
7	Wylie Ridge	Transformer	AP	$6.1	$7.4	$5.4	$4.1	($1.1)	($0.5)	($7.2)	($7.7)	($3.6)	354	335
8	Belmont	Transformer	AP	$3.2	$0.2	$0.6	$3.6	($0.2)	$0.4	($0.1)	($0.7)	$2.9	871	71
9	Bedington - Harmony	Line	AP	$2.0	($0.1)	$0.5	$2.6	$0.0	$0.0	($0.0)	($0.1)	$2.6	262	28
10	Doubs	Transformer	AP	$2.0	($0.3)	$0.0	$2.4	$0.2	$0.1	($0.1)	$0.0	$2.4	84	30
11	Cloverdale - Lexington	Line	AEP	$1.2	($1.3)	$0.8	$3.3	($0.1)	$0.0	($0.9)	($1.0)	$2.3	752	335
12	Carroll - Catoctin	Line	AP	$0.4	$0.0	($0.0)	$0.3	$0.7	($0.8)	$0.2	$1.6	$2.0	99	22
13	Yukon	Transformer	AP	$2.2	$0.4	$0.0	$1.8	$0.0	$0.2	$0.1	($0.1)	$1.7	142	39
14	West	Interface	500	($12.5)	($15.3)	($2.0)	$0.8	$0.3	$0.2	$0.4	$0.5	$1.3	391	85
15	Kingwood - Pruntytown	Line	AP	$1.0	($0.1)	($0.0)	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.1	158	7
16	Mount Storm	Transformer	AP	($0.4)	($1.8)	($0.2)	$1.1	$0.2	$0.5	$0.3	($0.1)	$1.1	123	70
17	Middlebourne - Willow	Line	AP	$1.2	$0.1	($0.1)	$1.0	($0.0)	($0.1)	($0.0)	$0.0	$1.0	227	38
18	Krendale - Seneca	Line	AP	$0.8	$0.0	$0.2	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	245	0
19	Bedington	Transformer	AP	$4.2	($0.8)	$0.1	$5.1	($3.7)	$0.0	($2.2)	($6.0)	($0.9)	338	149
21	Sammis - Wylie Ridge	Line	AP	$3.0	$2.3	$1.5	$2.2	($0.2)	($0.2)	($1.2)	($1.3)	$0.9	632	140

ComEd Control Zone

Table 7-45 ComEd Control Zone top congestion cost impacts (By facility): January through September 2010 (See 2009 SOM, Table 7-45)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	East Frankfort - Crete	Line	ComEd	($33.4)	($62.5)	($4.2)	$24.9	($2.7)	$0.3	$1.1	($2.0)	$22.9	2,242	797
2	AP South	Interface	500	($76.0)	($101.3)	($0.7)	$24.6	($2.4)	$0.4	($0.0)	($2.8)	$21.8	3,512	1,251
3	Electric Jct - Nelson	Line	ComEd	$1.0	($23.6)	$6.4	$31.0	$1.2	$3.5	($7.6)	($9.9)	$21.1	1,454	236
4	Crete - St Johns Tap	Flowgate	Midwest ISO	($19.1)	($31.2)	($1.2)	$11.0	($0.7)	($1.0)	$0.4	$0.7	$11.7	800	245
5	Pleasant Valley - Belvidere	Line	ComEd	($3.2)	($16.9)	$1.3	$15.0	$0.1	$2.6	($1.9)	($4.5)	$10.6	1,775	355
6	Nelson - Cordova	Line	ComEd	$7.6	($2.4)	$3.3	$13.2	$0.6	$1.3	($3.4)	($4.0)	$9.2	965	90
7	Bedington - Black Oak	Interface	500	($26.9)	($35.1)	($0.2)	$8.0	($0.2)	$0.1	$0.0	($0.3)	$7.7	1,819	47
8	5004/5005 Interface	Interface	500	($26.1)	($36.0)	($0.1)	$9.8	($4.2)	($0.6)	$0.6	($2.9)	$6.9	1,379	561
9	Waterman - West Dekalb	Line	ComEd	($1.7)	($7.3)	$0.8	$6.4	$0.4	$0.3	($0.2)	($0.0)	$6.4	2,543	288
10	AEP-DOM	Interface	500	($10.4)	($16.4)	($0.4)	$5.6	($0.1)	($0.2)	$0.0	$0.1	$5.7	471	89
11	Rising	Flowgate	Midwest ISO	($2.4)	($7.1)	($0.0)	$4.7	($0.0)	$0.0	$0.0	($0.0)	$4.6	776	44
12	Cloverdale - Lexington	Line	AEP	($11.5)	($17.5)	($0.4)	$5.7	($1.4)	$0.1	$0.4	($1.2)	$4.5	1,044	620
13	Doubs	Transformer	AP	($15.1)	($18.9)	($0.1)	$3.7	($1.0)	$0.6	$0.2	($1.3)	$2.3	806	431
14	Cherry Valley	Transformer	ComEd	$0.9	($1.1)	$0.2	$2.1	$0.0	$0.1	($0.1)	($0.1)	$2.0	104	37
15	Tiltonsville - Windsor	Line	AP	($9.3)	($12.2)	($0.2)	$2.6	($1.1)	$0.0	$0.5	($0.7)	$1.9	1,954	410
18	Glidden - West Dekalb	Line	ComEd	$0.0	($1.6)	$0.2	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	376	0
21	Electric Junction - Aurora	Line	ComEd	$1.3	$0.2	$0.0	$1.1	$0.0	$0.1	$0.1	$0.1	$1.2	136	35
22	Woodstock - 12205	Line	ComEd	($0.0)	($1.1)	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	91	0
30	Burnham - Munster	Line	ComEd	($0.0)	($0.0)	($0.0)	$0.0	($0.0)	$0.6	($0.0)	($0.7)	($0.7)	1	82
32	Belvidere - Woodstock	Line	ComEd	$0.3	($0.4)	$0.1	$0.7	$0.0	$0.1	($0.0)	($0.0)	$0.7	60	7

Table 7-46 ComEd Control Zone top congestion cost impacts (By facility): January through September 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	($3.0)	($28.1)	$0.1	$25.1	$1.1	$1.5	$0.0	($0.3)	$24.8	2,342	266
2	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($45.7)	($69.8)	($3.1)	$21.0	($3.4)	($1.1)	$0.9	($1.4)	$19.6	2,888	907
3	Kammer	Transformer	500	($30.8)	($49.7)	($0.1)	$18.7	($0.4)	($0.9)	($0.0)	$0.4	$19.1	3,674	1,328
4	East Frankfort - Crete	Line	ComEd	($14.8)	($29.9)	($0.1)	$15.0	($0.5)	($0.5)	($0.1)	($0.1)	$14.9	1,490	219
5	AP South	Interface	500	($25.4)	($37.9)	($0.1)	$12.5	($1.0)	($0.5)	($0.1)	($0.5)	$12.0	2,559	423
6	Crete - St Johns Tap	Flowgate	Midwest ISO	($9.4)	($19.7)	($0.2)	$10.1	($0.4)	($0.1)	($0.0)	($0.3)	$9.8	732	190
7	Electric Jct - Nelson	Line	ComEd	$0.2	($7.9)	$0.1	$8.2	$2.1	$1.4	($0.1)	$0.6	$8.8	819	202
8	5004/5005 Interface	Interface	500	($10.4)	($14.4)	($0.0)	$3.9	($0.6)	($1.1)	($0.0)	$0.5	$4.4	643	241
9	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
10	Glidden - West Dekalb	Line	ComEd	($0.2)	($4.0)	$0.1	$3.8	$0.0	$0.0	$0.0	$0.0	$3.8	703	0
11	Wylie Ridge	Transformer	AP	($7.9)	($10.9)	($0.0)	$3.0	($0.8)	($1.5)	$0.0	$0.8	$3.8	354	335
12	West	Interface	500	($11.4)	($14.9)	($0.0)	$3.5	($0.1)	($0.1)	($0.0)	$0.0	$3.6	391	85
13	Mount Storm - Pruntytown	Line	AP	($4.1)	($6.8)	($0.0)	$2.7	($0.2)	($0.6)	($0.0)	$0.4	$3.2	525	132
14	Cloverdale - Lexington	Line	AEP	($4.5)	($7.8)	($0.0)	$3.3	($0.6)	($0.3)	$0.0	($0.3)	$3.1	752	335
15	Oak Grove - Galesburg	Flowgate	Midwest ISO	($0.4)	($3.5)	$0.0	$3.1	$1.1	$1.0	($0.2)	($0.2)	$2.9	645	531
16	Cherry Valley	Transformer	ComEd	$0.4	($2.4)	$0.0	$2.8	$0.0	$0.0	$0.0	($0.0)	$2.8	25	6
19	Wilton Center - Pontiac	Line	ComEd	$1.6	$0.4	$0.0	$1.3	$0.1	$0.7	$0.0	($0.6)	$0.7	0	0
21	Waterman - West Dekalb	Line	ComEd	($0.3)	($1.4)	$0.0	$1.1	$0.1	($0.0)	($0.0)	$0.1	$1.2	1,216	41
24	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
25	Burnham - Munster	Line	ComEd	($2.1)	($3.4)	($0.0)	$1.3	($0.0)	$0.0	($0.0)	($0.1)	$1.2	140	15

DAY Control Zone

Table 7-47 DAY Control Zone top congestion cost impacts (By facility): January through September 2010 (See 2009 SOM, Table 7-47)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($1.4)	($2.5)	($0.2)	$0.9	$0.3	($0.0)	$0.4	$0.7	$1.6	1,379	561
2	AP South	Interface	500	($4.6)	($6.3)	($0.9)	$0.8	($0.0)	$0.4	$0.6	$0.2	$1.0	3,512	1,251
3	Cloverdale - Lexington	Line	AEP	($0.5)	($1.4)	($0.3)	$0.6	$0.1	($0.0)	$0.2	$0.4	$1.0	1,044	620
4	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	($0.0)	$0.5	$0.5	($0.0)	$0.0	($1.4)	($1.4)	($0.9)	1,098	212
5	AEP-DOM	Interface	500	($0.7)	($1.4)	($0.0)	$0.7	($0.0)	($0.0)	$0.0	$0.0	$0.7	471	89
6	Mount Storm - Pruntytown	Line	AP	($0.4)	($0.5)	($0.0)	$0.1	$0.2	$0.2	$0.7	$0.6	$0.7	571	574
7	Harrison - Pruntytown	Line	500	($0.1)	($0.2)	($0.0)	$0.0	$0.1	$0.1	$0.4	$0.5	$0.5	231	224
8	Tiltonsville - Windsor	Line	AP	($0.6)	($0.8)	($0.3)	($0.1)	$0.1	($0.0)	$0.4	$0.5	$0.5	1,954	410
9	Waterman - West Dekalb	Line	ComEd	$0.0	$0.0	$0.5	$0.5	$0.0	$0.0	($0.1)	($0.1)	$0.4	2,543	288
10	Pleasant Valley - Belvidere	Line	ComEd	$0.0	$0.0	$0.8	$0.8	($0.0)	$0.0	($1.2)	($1.2)	($0.4)	1,775	355
11	Branchburg - Flagtown	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	0
12	Doubs	Transformer	AP	($0.9)	($1.2)	($0.1)	$0.3	$0.1	$0.1	$0.1	$0.1	$0.4	806	431
13	Bedington - Black Oak	Interface	500	($1.4)	($2.2)	($0.4)	$0.3	($0.0)	$0.0	$0.0	$0.0	$0.4	1,819	47
14	Dumont - Stillwell	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.3)	($0.3)	156	124
15	Clover	Transformer	Dominion	($0.2)	($0.4)	$0.1	$0.3	$0.0	($0.1)	($0.0)	$0.0	$0.3	464	243
133	Hutchings - Sugarcreek	Line	DAY	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	1

Table 7-48 DAY Control Zone top congestion cost impacts (By facility): January through September 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	($1.9)	($4.5)	($0.1)	$2.6	$0.4	($0.1)	$0.0	$0.5	$3.1	3,674	1,328
2	AP South	Interface	500	($1.9)	($2.9)	($0.0)	$1.0	$0.1	$0.2	($0.0)	($0.1)	$0.9	2,559	423
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.4	$1.0	($0.5)	($1.1)	($0.0)	($0.0)	$0.1	$0.2	($0.9)	2,888	907
4	West	Interface	500	($0.8)	($1.4)	$0.0	$0.7	$0.0	$0.0	$0.0	($0.0)	$0.7	391	85
5	Wylie Ridge	Transformer	AP	($0.6)	($1.1)	($0.0)	$0.5	$0.2	$0.2	$0.0	($0.0)	$0.4	354	335
6	Cloverdale - Lexington	Line	AEP	($0.3)	($0.8)	$0.0	$0.5	$0.0	$0.1	$0.0	($0.1)	$0.4	752	335
7	5004/5005 Interface	Interface	500	($0.7)	($1.0)	($0.0)	$0.3	$0.1	$0.1	$0.0	$0.0	$0.3	643	241
8	Tiltonsville - Windsor	Line	AP	($0.2)	($0.6)	($0.0)	$0.4	$0.0	$0.1	$0.0	($0.1)	$0.3	1,258	237
9	Marquis - Waverly	Line	AEP	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.2	74	14
10	Elrama - Mitchell	Line	AP	($0.1)	($0.3)	($0.0)	$0.2	$0.1	$0.0	$0.0	$0.1	$0.2	225	184
11	Sammis - Wylie Ridge	Line	AP	($0.2)	($0.4)	($0.0)	$0.2	$0.0	$0.1	($0.0)	($0.0)	$0.2	632	140
12	Pierce - Foster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.0)	($0.2)	($0.2)	0	5
13	East Frankfort - Crete	Line	ComEd	$0.2	$0.3	$0.0	($0.1)	($0.0)	($0.0)	($0.0)	($0.0)	($0.1)	1,490	219
14	Kammer - Ormet	Line	AEP	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	552	509
15	Breed - Wheatland	Line	AEP	$0.0	$0.1	$0.0	($0.1)	$0.0	($0.0)	($0.0)	$0.0	($0.1)	511	2

DLCO Control Zone

Table 7-49 DLCO Control Zone top congestion cost impacts (By facility): January through September 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	$12.3	$0.1	$0.2	$12.4	$0.2	($0.5)	($0.3)	$0.4	$12.8	630	141
2	AP South	Interface	500	($34.9)	($41.5)	($0.2)	$6.4	($2.1)	($0.3)	$0.2	($1.5)	$4.8	3,512	1,251
3	Collier - Elwyn	Line	DLCO	$4.5	$0.3	$0.1	$4.4	($0.0)	($0.1)	($0.0)	$0.0	$4.4	460	111
4	Carson - Oakland	Line	DLCO	$2.5	$0.0	$0.0	$2.5	($0.0)	($0.0)	$0.0	($0.0)	$2.5	170	1
5	Bedington - Black Oak	Interface	500	($10.6)	($12.3)	($0.1)	$1.7	($0.2)	($0.1)	$0.0	($0.1)	$1.6	1,819	47
6	AEP-DOM	Interface	500	($4.3)	($5.7)	($0.0)	$1.4	($0.2)	($0.1)	$0.0	($0.1)	$1.3	471	89
7	Sammis - Wylie Ridge	Line	AP	($1.8)	($3.2)	($0.0)	$1.4	($0.1)	$0.2	$0.0	($0.2)	$1.2	521	60
8	East Frankfort - Crete	Line	ComEd	$1.1	$2.0	($0.0)	($0.9)	$0.1	($0.0)	($0.0)	$0.1	($0.7)	2,242	797
9	Elrama - Mitchell	Line	AP	($2.4)	($1.9)	($0.1)	($0.6)	($0.1)	$0.0	$0.1	($0.0)	($0.6)	411	239
10	5004/5005 Interface	Interface	500	($10.0)	($11.8)	($0.1)	$1.7	($1.3)	($0.1)	$0.1	($1.1)	$0.6	1,379	561
11	Cloverdale - Lexington	Line	AEP	($1.4)	($2.1)	$0.0	$0.7	($0.2)	($0.0)	($0.0)	($0.2)	$0.5	1,044	620
12	Arsenal - Highland	Line	DLCO	$0.5	($0.0)	$0.0	$0.5	($0.0)	$0.0	($0.0)	($0.0)	$0.4	41	7
13	Collier	Transformer	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	8	8
14	Arsenal - Oakland	Line	DLCO	$0.1	($0.1)	$0.0	$0.2	($0.3)	$0.2	($0.0)	($0.5)	($0.3)	72	46
15	Wylie Ridge	Transformer	AP	($1.7)	($2.8)	($0.0)	$1.0	($0.7)	$0.6	$0.0	($1.3)	($0.3)	479	376
16	Beaver - Mansfield	Line	DLCO	($0.1)	($0.4)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	163	0
23	Crescent - Sewickly	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	12	0
25	Beaver	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.0)	($0.1)	($0.1)	0	7
26	Cheswick - Logan's Ferry	Line	DLCO	$0.0	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	17	0
28	Arsenal	Transformer	DLCO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	8	0

Table 7-50 DLCO Control Zone top congestion cost impacts (By facility): January through September 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	($0.2)	$0.5	$0.0	($0.7)	$3.3	632	140
2	AP South	Interface	500	($10.8)	($14.9)	($0.0)	$4.1	($0.7)	$0.3	$0.0	($1.0)	$3.1	2,559	423
3	Elrama - Mitchell	Line	AP	($2.7)	($1.8)	($0.0)	($0.9)	($0.2)	$0.9	$0.0	($1.1)	($2.1)	225	184
4	West	Interface	500	($3.8)	($5.5)	($0.0)	$1.6	($0.1)	$0.0	$0.0	($0.1)	$1.5	391	85
5	Logans Ferry - Universal	Line	DLCO	$0.2	($1.3)	$0.0	$1.5	$0.0	$0.1	($0.0)	($0.1)	$1.4	395	156
6	Collier	Transformer	DLCO	$1.4	$0.3	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	46	0
7	Wylie Ridge	Transformer	AP	($8.5)	($12.9)	($0.0)	$4.4	($1.2)	$2.2	$0.0	($3.3)	$1.1	354	335
8	Kammer	Transformer	500	($3.6)	($4.8)	$0.0	$1.3	($0.4)	($0.1)	($0.0)	($0.4)	$0.9	3,674	1,328
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.7	$2.6	($0.0)	($0.9)	$0.2	$0.1	($0.0)	$0.1	($0.8)	2,888	907
10	Mount Storm - Pruntytown	Line	AP	($1.9)	($2.8)	($0.0)	$0.9	($0.2)	$0.1	$0.0	($0.3)	$0.6	525	132
11	East Frankfort - Crete	Line	ComEd	$0.7	$1.1	$0.0	($0.4)	$0.0	$0.0	($0.0)	$0.0	($0.4)	1,490	219
12	Krendale - Seneca	Line	AP	($0.7)	($1.0)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	245	0
13	Kammer - West Bellaire	Line	AP	$0.3	$0.3	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.3	$0.3	50	19
14	Cloverdale - Lexington	Line	AEP	($0.7)	($1.1)	$0.0	$0.4	($0.1)	$0.0	($0.0)	($0.1)	$0.3	752	335
15	Bedington - Black Oak	Interface	500	($1.2)	($1.6)	($0.0)	$0.3	($0.0)	$0.0	$0.0	($0.1)	$0.3	395	61
16	Beaver - Clinton	Line	DLCO	$0.1	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	20	0
22	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
24	Cheswick - Evergreen	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	35	5
25	Cheswick - Wilmerding	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	35	0
37	Crescent	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.2	$0.1	($0.0)	$0.0	$0.0	0	20

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-51 Dominion Control Zone top congestion cost impacts (By facility): January through September 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	$84.5	($26.0)	$0.7	$111.2	$2.8	$4.9	($0.9)	($2.9)	$108.3	3,512	1,251
2	Cloverdale - Lexington	Line	AEP	$18.0	$5.6	$2.0	$14.4	($1.8)	($2.4)	($2.3)	($1.6)	$12.8	1,044	620
3	Doubs	Transformer	AP	($0.1)	($11.4)	($0.1)	$11.2	$1.5	$0.8	$0.7	$1.4	$12.6	806	431
4	Bedington - Black Oak	Interface	500	$27.2	$20.5	$3.0	$9.7	($0.2)	($0.2)	($0.3)	($0.3)	$9.4	1,819	47
5	Clover	Transformer	Dominion	$6.1	($2.0)	$1.5	$9.5	($0.3)	$0.5	($1.2)	($2.0)	$7.5	464	243
6	Pleasant View	Transformer	Dominion	$0.3	$0.0	$0.0	$0.3	($4.2)	$1.4	($0.6)	($6.3)	($6.0)	31	101
7	Millville - Old Chapel	Line	AP	$0.4	($2.8)	($0.4)	$2.8	$0.9	$0.6	$1.6	$1.9	$4.7	178	121
8	Ox - Francona	Line	Dominion	$3.3	($0.6)	$0.0	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	66	0
9	AEP-DOM	Interface	500	$15.3	$12.5	$0.6	$3.4	($0.1)	($0.3)	($0.1)	$0.1	$3.5	471	89
10	Ox - Glebe	Line	Dominion	$2.5	($0.7)	$0.0	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	30	0
11	Chuckatuck - Benns Church	Line	Dominion	$2.5	($0.2)	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	76	0
12	5004/5005 Interface	Interface	500	($2.6)	($4.6)	$0.3	$2.3	$1.3	$1.3	$0.3	$0.4	$2.7	1,379	561
13	East Frankfort - Crete	Line	ComEd	$4.3	$2.4	$0.2	$2.1	($0.2)	($0.4)	($0.2)	($0.0)	$2.1	2,242	797
14	Endless Caverns	Transformer	Dominion	$0.6	($1.4)	$0.0	$2.0	($0.0)	($0.0)	$0.0	$0.0	$2.0	541	3
15	West	Interface	500	($1.5)	($3.5)	($0.1)	$2.0	$0.1	$0.1	$0.1	$0.0	$2.0	159	58
16	Dooms	Transformer	Dominion	$1.3	($0.2)	$0.0	$1.5	($0.5)	($0.8)	$0.1	$0.4	$1.8	34	31
17	Greenwich - Elizabeth River	Line	Dominion	$1.6	($0.2)	$0.0	$1.8	$0.1	$0.0	($0.0)	$0.0	$1.8	32	22
18	Pleasant View	Line	Dominion	$1.8	$0.1	$0.1	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	32	0
19	Yadkin	Transformer	Dominion	$1.5	$0.1	$0.0	$1.5	$0.4	$0.0	($0.1)	$0.3	$1.7	26	21
20	Beechwood - Kerr Dam	Line	Dominion	$1.8	($1.2)	($0.1)	$2.8	($0.7)	$0.5	$0.1	($1.1)	$1.7	582	306

Table 7-52 Dominion Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2009 SOM, Table 7-52)

				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	$26.0	($20.9)	($0.4)	$46.6	$1.1	$0.1	$0.2	$1.1	$47.7	2,559	423
2	Cloverdale - Lexington	Line	AEP	$5.8	$2.4	$0.9	$4.3	($0.1)	($1.8)	($1.2)	$0.5	$4.8	752	335
3	Kammer	Transformer	500	$10.3	$8.3	$2.1	$4.2	($0.0)	($0.8)	($2.0)	($1.2)	$3.0	3,674	1,328
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$4.3	$2.1	$0.1	$2.3	($0.2)	($0.6)	($0.1)	$0.3	$2.6	2,888	907
5	Beechwood - Kerr Dam	Line	Dominion	$1.5	($0.8)	($0.1)	$2.2	($0.2)	$0.1	$0.1	($0.2)	$2.0	632	228
6	Chuckatuck - Benns Church	Line	Dominion	$1.5	($0.0)	$0.0	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	45	0
7	Bedington - Black Oak	Interface	500	$2.6	$1.6	$0.6	$1.5	($0.1)	($0.1)	($0.2)	($0.1)	$1.4	395	61
8	West	Interface	500	($2.4)	($3.3)	$0.0	$1.0	$0.1	$0.2	$0.1	$0.0	$1.0	391	85
9	Wylie Ridge	Transformer	AP	$2.5	$1.7	$0.4	$1.2	($0.1)	($0.2)	($0.4)	($0.2)	$1.0	354	335
10	Ox	Transformer	Dominion	$0.8	($0.1)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	8	0
11	Crozet - Dooms	Line	Dominion	$0.7	($0.3)	$0.0	$1.0	($0.3)	($0.2)	($0.0)	($0.1)	$0.9	54	37
12	5004/5005 Interface	Interface	500	($0.6)	($1.3)	($0.1)	$0.6	$0.1	$0.1	$0.0	$0.1	$0.7	643	241
13	Chickahominy - Lanexa	Line	Dominion	$0.5	($0.0)	$0.0	$0.6	($0.1)	($0.3)	$0.0	$0.1	$0.7	42	19
14	Clover - Farmville	Line	Dominion	($0.0)	($0.7)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	41	0
15	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.0	$0.5	$0.1	$0.6	($0.1)	($0.2)	($0.1)	$0.0	$0.7	732	190
17	Crozet - Barracks Rd	Line	Dominion	$0.8	$0.3	($0.0)	$0.4	$0.1	($0.1)	$0.0	$0.2	$0.6	39	11
21	Beaumeade - Ashburn	Line	Dominion	$0.4	$0.0	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	15	0
25	Lightfoot - Chickahominy	Line	Dominion	$0.0	($0.0)	$0.0	$0.0	($0.2)	$0.2	($0.0)	($0.4)	($0.4)	7	10
27	Danville - East Danville	Line	Dominion	$0.7	$0.4	$0.0	$0.4	($0.1)	($0.0)	($0.0)	($0.0)	$0.3	165	36
28	Dooms	Transformer	Dominion	$0.3	($0.0)	($0.0)	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	15	5

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs 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 September* focuses on 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.

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 from 2009 through 2012. The second Long Term FTR Auction was conducted during the 2009 to 2010 planning period and covers the three consecutive planning periods from 2010 through 2013. The 2011 to 2014 Long Term FTR Auction results are not presented in this report because the second round results were not posted until after the end of the third quarter. 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 Auctions. 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. Market participants can also sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first four months (June through September 2010) of the 2010 to 2011 planning period, there were 1,686,988 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the Monthly Balance of Planning Period FTR Auctions for the first four

1 87 FERC ¶ 61,054 (1999).

months (June through September 2010) of the 2010 to 2011 planning period, total FTR buy bids were 4,924,599 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 nine months of 2010.
  - **Tower Companies Litigation and Investigation.** On July 23, 2010, PJM reported that it had settled litigation brought against the Tower Companies arising from the default of their affiliate Power Edge, LLC in 2007 in Federal Court and at the FERC.[2] This matter concerned in part allegations that the Tower Companies "manipulated PJM's Day-ahead energy and Financial Transmission Rights (FTR) markets."[3] The FERC also commenced its own independent investigation.[4] The Market Monitor had been scheduled to testify in the Court proceeding as a fact witness and as a non-retained or employed expert witness on the basis of the MMU's extensive non-public analysis. Under the terms of the settlement, the Tower Companies paid $18 million in return for PJM withdrawing its civil complaint and the remainder of its complaint at the FERC related to this matter. In September 2010, the PJM Members Committee adopted and then implemented the following resolution: "The PJM Members Committee resolves to request the chair of the Members Committee to send a letter to FERC Office of Enforcement to request expeditious conclusion of the investigation of Tower affiliates in the matter of alleged improper use of virtual trades and make public the results of that investigation consistent with FERC practices and procedures."[5]

- **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. Financial entities own about 63 percent of prevailing flow and 73 percent of counter flow FTRs from the January through September 2010 Monthly Balance of Planning Period Auctions. Overall, financial entities own about 68 percent of all Monthly Balance of Planning Period FTRs during the same time period.

Market Performance

- **Volume.** For the first four months of the 2010 to 2011 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 580,753 MW (11.8 percent) of FTR buy bids and 169,659 MW (10.1 percent) of FTR sell offers.

- **Price.** The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2010 to 2011 planning period was $0.20 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 Monthly Balance of Planning Period FTR Auctions generated $11.1 million in net revenue for all FTRs during the first four months 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 92.1 percent of the target allocation level for the first four months of the 2010 to 2011 planning period. The months of March, April and September had the lowest payout ratios before adjustments in 2010, which were 74 percent, 69 percent and 70 percent. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $693.9 million of FTR revenues during the first four months of the 2010 to 2011 planning period and $878.4 million during the 2009 to 2010 planning period. For the first four months of the 2010 to 2011 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Mount Storm aggregate, respectively. Similarly, the top sink and top source with the largest negative FTR target allocation was the Western Hub.

2 See FERC Docket No. EL08-44 and the Federal Court proceedings in United States District Counts in Delaware and Pennsylvania, DE No. 08-216-JJF and Eastern Dist PA, C.A. No. 08-CV-3649-NS.
3 See 127 FERC ¶61,007 at P 1 (2009).
4 *Id.*
5 See letter from Edward D. Tatum, Chair, PJM Members Committee, to Norman Bay, Director, Office of Enforcement (FERC) dated September 27, 2010, which can be accessed at <http://www.pjm.com/~/media/committees-groups/committees/mc/20100923/20100923-item-05-mc-chair-letter-to-ferc-oe.ashx>.

Auction Revenue Rights

Market Structure

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 11,813 MW of ARRs associated with approximately $162,100 per MW-day of revenue that were reassigned in the first four months 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

- **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 $1,061 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through September 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.

- **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. For the 2009 to 2010 planning period, all ARRs and FTRs hedged 96.4 percent of the congestion costs within PJM. During the first four months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 98.2 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 3.6 percent of the total real time energy charges for January through September 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 0.7 percent of the total real time energy charges for January through September 2010. When combined, the sum is a measure of the total value of ARRs plus FTRs. The total value of ARRs plus FTRs was 4.3 percent of the total real time energy charges for January through September 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.

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 92.1 percent of the target allocation level for the first four months 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 96.4 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2009 to 2010 planning period and 98.2 percent of the congestion costs in PJM during the first four months of the 2010 to 2011 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

Financial Transmission Rights

Patterns of Ownership

Table 8-1 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September 2010 (See 2009 SOM Table 8-5)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	36.6%	26.6%	32.3%
Financial	63.4%	73.4%	67.7%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-2 Monthly Balance of Planning Period FTR Auction market volume: January through September 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%
Jul-10	Obligations	Buy bids	225,737	1,108,721	146,069	13.2%	962,652	86.8%
		Sell offers	75,886	359,722	29,406	8.2%	330,316	91.8%
	Options	Buy bids	878	37,271	2,304	6.2%	34,967	93.8%
		Sell offers	8,089	66,097	16,084	24.3%	50,013	75.7%

Table 8-2 Monthly Balance of Planning Period FTR Auction market volume: January through September 2010 (See 2009 SOM Table 8-9) [continued]

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Aug-10	Obligations	Buy bids	222,224	1,118,261	126,436	11.3%	991,825	88.7%
		Sell offers	65,197	300,616	23,910	8.0%	276,706	92.0%
	Options	Buy bids	2,532	83,876	4,233	5.0%	79,643	95.0%
		Sell offers	6,321	42,262	13,534	32.0%	28,728	68.0%
Sep-10	Obligations	Buy bids	232,043	1,282,913	185,736	14.5%	1,097,177	85.5%
		Sell offers	76,919	364,793	31,628	8.7%	333,165	91.3%
	Options	Buy bids	1,681	227,899	5,366	2.4%	222,533	97.6%
		Sell offers	8,339	66,072	15,052	22.8%	51,020	77.2%
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	884,309	4,508,818	565,918	12.6%	3,942,900	87.4%
		Sell offers	312,435	1,442,866	109,172	7.6%	1,333,694	92.4%
	Options	Buy bids	6,816	415,781	14,835	3.6%	400,946	96.4%
		Sell offers	33,822	244,122	60,487	24.8%	183,636	75.2%

* Shows Twelve Months for 2009/2010; ** Shows four months ended 30-Sep-2010 for 2010/2011

Table 8-3 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January through September 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	55,053	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
Jul-10	Bid	529,368	142,953	88,144		129,524	130,924	125,079	1,145,991
	Cleared	86,820	15,281	8,068		13,336	12,559	12,309	148,373
Aug-10	Bid	566,562	113,783	102,176		130,975	140,738	147,904	1,202,137
	Cleared	76,858	10,504	9,822		8,898	11,734	12,854	130,669
Sep-10	Bid	618,218	186,274	173,686		96,649	215,233	220,752	1,510,812
	Cleared	117,485	18,384	18,820		6,981	13,593	15,840	191,103

Table 8-4 Secondary bilateral FTR market volume: Planning periods 2009 to 2010 and 2010 to 2011[6] (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	8,810	$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	1,562	$0.06
		On Peak	9,740	$0.00
		Off Peak	12,133	$0.00
		Total	23,434	$0.03
	Option	24-Hour	20	$0.40
		On Peak	0	NA
		Off Peak	0	NA
		Total	20	$0.40

* Shows four months ended 30-Sep-2010

Price

Table 8-5 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January through September 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
Jul-10	$0.14	$0.46	$0.04		$0.19	$0.16	$0.15	$0.17
Aug-10	$0.19	$0.36	$0.18		$0.20	$0.35	$0.13	$0.22
Sep-10	$0.13	$0.17	$0.15		$0.09	$0.20	$0.14	$0.14

6 The 2010 to 2011 planning period covers the 2010 to 2011 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through September 30, 2010.

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 8-6 Monthly Balance of Planning Period FTR Auction revenue: January through September 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	NA	$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	NA	$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	NA	$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
Jul-10	Obligations	Buy bids	($524,716)	$8,542,586	$5,945,266	$13,963,136
		Sell offers	$6,087	$2,569,941	$1,806,154	$4,382,181
	Options	Buy bids	$17,289	$270,145	$135,568	$423,002
		Sell offers	$1,672,986	$2,791,024	$2,166,674	$6,630,683

Table 8-6 Monthly Balance of Planning Period FTR Auction revenue: January through September 2010 (See 2009 SOM Table 8-17) [continued]

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Aug-10	Obligations	Buy bids	$1,995,876	$8,489,218	$5,226,059	$15,711,153
		Sell offers	$78,088	$6,252,007	$3,227,745	$9,557,840
	Options	Buy bids	$0	$197,801	$157,086	$354,887
		Sell offers	$30,431	$1,626,257	$1,836,640	$3,493,328
Sep-10	Obligations	Buy bids	$590,917	$6,987,726	$5,639,454	$13,218,098
		Sell offers	$135,907	$3,907,689	$2,637,138	$6,680,733
	Options	Buy bids	$0	$333,742	$312,661	$646,403
		Sell offers	$123,445	$1,921,160	$2,853,356	$4,897,961
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	$5,310,632	$32,086,097	$22,908,652	$60,305,381
		Sell offers	$1,173,815	$16,605,891	$11,396,370	$29,176,076
	Options	Buy bids	$23,091	$960,540	$722,076	$1,705,707
		Sell offers	$1,843,701	$10,604,071	$9,250,658	$21,698,429

* Shows twelve months for 2009/2010; ** Shows four months ended 30-Sep-2010 for 2010/2011

Figure 8-1 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2010 to 2011 through September 30, 2010 (See 2009 SOM Figure 8-7)

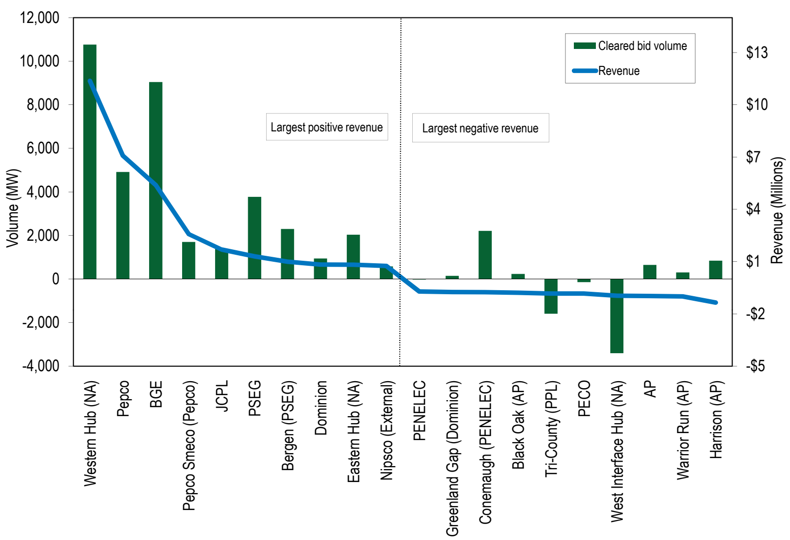
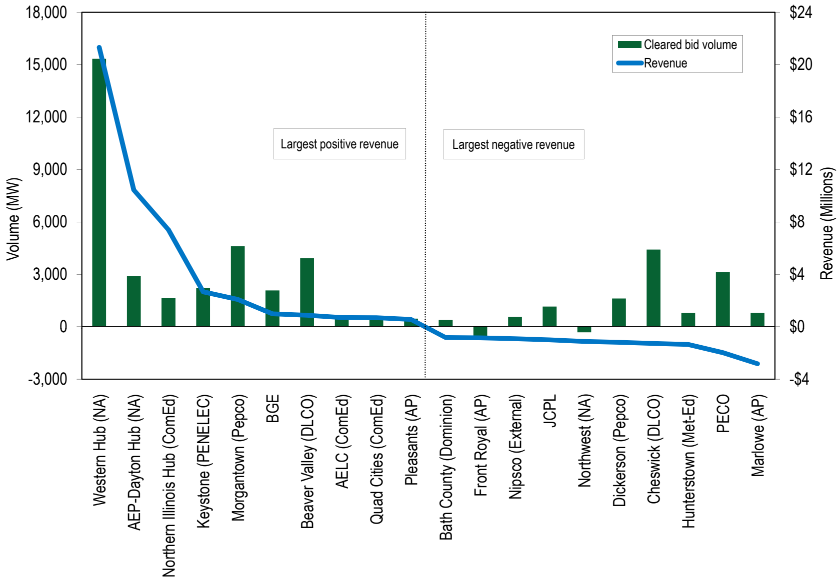


Figure 8-2 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2010 to 2011 through September 30, 2010 (See 2009 SOM Figure 8-8)



Revenue Adequacy

Table 8-7 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	$344.0
FTR auction revenue	$1,368.7	$365.4
ARR excess	$91.9	$21.3
FTR targets		
FTR target allocations	$908.1	$754.3
Adjustments:		
Adjustments to FTR target allocations	($1.5)	($0.5)
Total FTR targets	$906.6	$196.4
FTR revenues		
ARR excess	$91.9	$21.3
Competing uses	$0.0	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($37.8)	($7.9)
Hourly congestion revenue	$854.9	$691.0
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($31.0)	($10.0)
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)	($0.5)
Adjustments:		
Excess revenues carried forward into future months	$27.3	$0.0
Excess revenues distributed back to previous months	$9.2	$1.8
Other adjustments to FTR revenues	$2.4	($0.0)
Total FTR revenues	$923.5	($0.0)
Excess revenues distributed to other months	($45.1)	($1.8)
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	$693.9
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$880.3	$694.4
Remaining deficiency	$28.3	$59.9

* Shows four months ended 30-Sep-10

Table 8-8 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	$111.0	100.0%	$111.0	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	$193.9	$196.1	97.8%	$193.9	98.9%	$2.2	$0.0
Jul-10	$274.8	$273.0	100.0%	$273.0	100.0%	$0.0	$0.0
Aug-10	$111.1	$119.2	93.2%	$111.1	93.2%	$8.1	$0.0
Sep-10	$115.9	$165.5	70.0%	$115.9	70.0%	$49.6	$0.0
			Summary for Planning Period 2010 to 2011 through September 30, 2010				
Total		$753.8		$693.9	92.1%	$59.9	$0.0

Figure 8-3 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2010 to 2011 through September 30, 2010 (See 2009 SOM Figure 8-9)

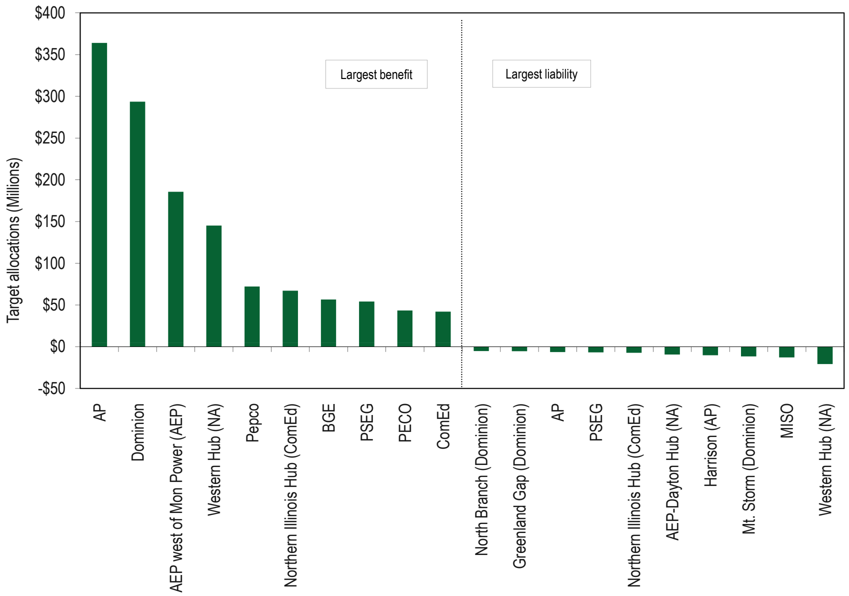
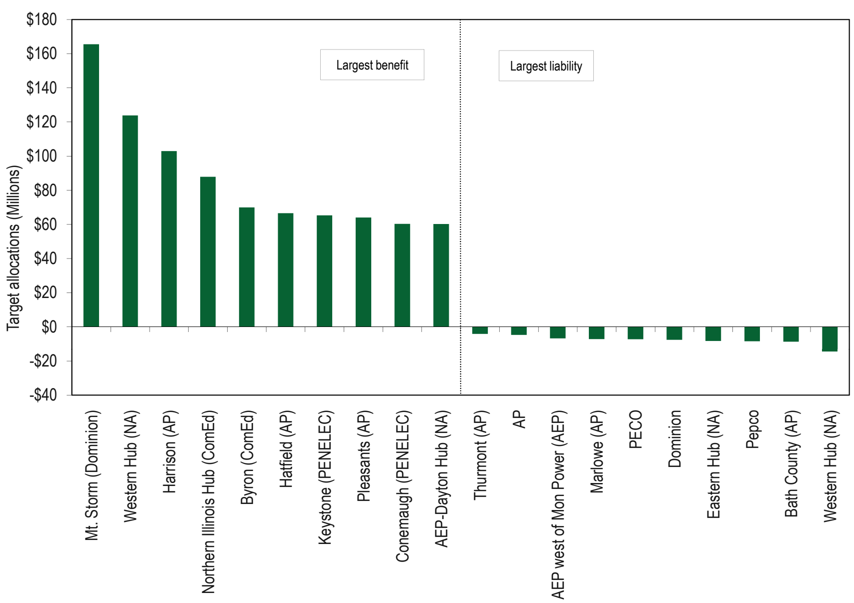


Figure 8-4 Ten largest positive and negative FTR target allocations summed by source: Planning period 2010 to 2011 through September 30, 2010 (See 2009 SOM Figure 8-10)



Auction Revenue Rights

Market Structure

ARR Reassignment for Retail Load Switching

Table 8-9 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2009, through September 30, 2010 (See 2009 SOM Table 8-22)

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2009/2010 (12 months)	2010/2011 (4 months)*	2009/2010 (12 months)	2010/2011 (4 months)*
AECO	417	499	$7.6	$2.6
AEP	268	181	$6.3	$3.7
AP	629	414	$77.2	$40.2
BGE	2,992	2,036	$62.9	$27.7
ComEd	3,145	1,188	$10.2	$12.6
DAY	21	62	$0.1	$0.2
DLCO	371	119	$1.0	$0.7
Dominion	0	0	$0.0	$0.0
DPL	952	616	$10.9	$4.7
JCPL	1,151	1,450	$17.7	$12.5
Met-Ed	33	147	$0.8	$1.9
PECO	29	16	$0.5	$0.2
PENELEC	8	21	$0.2	$0.3
Pepco	2,511	1,324	$25.6	$13.0
PPL	4,489	1,343	$91.4	$13.3
PSEG	1,984	2,305	$50.0	$28.4
RECO	62	92	$0.0	$0.0
Total	19,061	11,813	$362.4	$162.1

* Through 30-Sep-10

Market Performance

Revenue Adequacy

Table 8-10 ARR revenue adequacy (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011 (See 2009 SOM Table 8-24)

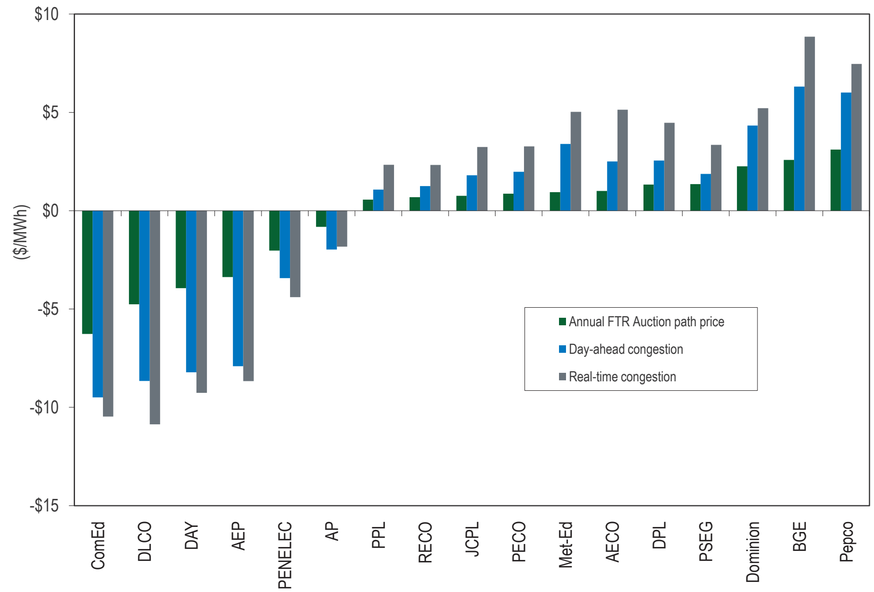
	2009/2010	2010/2011
Total FTR auction net revenue	$1,349.3	$1,061.0
Annual FTR Auction net revenue	$1,329.8	$1,049.8
Monthly Balance of Planning Period FTR Auction net revenue*	$19.5	$11.1
ARR target allocations	$1,273.5	$1,028.8
ARR credits	$1,273.5	$1,028.8
Surplus auction revenue	$75.8	$32.2
ARR payout ratio	100%	100%
FTR payout ratio*	96.9%	92.1%

* Shows twelve months for 2009/2010 and four months ended 30-Sep-10 for 2010/2011

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

Figure 8-5 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2010 to 2011 through September 30, 2010 (See 2009 SOM Figure 8-11)



Effectiveness of ARRs as a Hedge against Congestion

Table 8-11 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2010 to 2011 through September 30, 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	$5,616,622	$861,406	$6,478,028	$25,585,204	($19,107,176)	25.3%
AEP	$8,607,860	$47,721,396	$56,329,256	$120,649,410	($64,320,154)	46.7%
AP	$35,547,112	$160,166,470	$195,713,582	$45,623,155	$150,090,427	>100%
BGE	$29,986,713	$2,574,536	$32,561,249	$45,414,303	($12,853,054)	71.7%
ComEd	$82,312,055	$5,126,016	$87,438,071	($184,121,952)	$271,560,023	>100%
DAY	$3,657,086	$1,131,142	$4,788,228	$12,602,830	($7,814,602)	38.0%
DLCO	$5,052,309	$0	$5,052,309	$16,650,746	($11,598,437)	30.3%
Dominion	$4,992,312	$110,534,859	$115,527,171	($6,092,800)	$121,619,972	>100%
DPL	$11,521,197	$1,121,441	$12,642,638	$35,046,963	($22,404,325)	36.1%
JCPL	$15,996,256	$2,109,977	$18,106,233	$37,873,573	($19,767,340)	47.8%
Met-Ed	$13,272,652	$742,384	$14,015,036	$27,765,700	($13,750,664)	50.5%
PECO	$1,707,188	$18,808,093	$20,515,281	$825,164	$19,690,117	>100%
PENELEC	$23,696,177	$6,265	$23,702,442	$30,359,891	($6,657,449)	78.1%
Pepco	$20,673,905	$1,597,096	$22,271,001	$83,054,556	($60,783,554)	26.8%
PJM	$17,922,362	$1,360,316	$19,282,678	$12,986,687	$6,295,992	>100%
PPL	$20,247,335	$4,900,404	$25,147,739	$45,732,838	($20,585,099)	55.0%
PSEG	$38,443,453	$2,963,696	$41,407,149	$16,925,647	$24,481,502	>100%
RECO	$93,249	$0	$93,249	$1,466,351	($1,373,102)	6.4%
Total	$339,345,843	$361,725,497	$701,071,340	$368,348,263	$332,723,077	>100%

Effectiveness of FTRs as a Hedge against Congestion

Table 8-12 FTR congestion hedging by control zone: Planning period 2010 to 2011 through September 30, 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	($902,870)	($1,162,228)	$181,487			
	Prevailing Flow	$10,403,730	$7,684,048	$3,616,984			
	Total	$9,500,860	$6,521,820	$3,798,471	$18,244,997	($14,446,525)	20.8%
AEP	Counter Flow	($6,877,950)	($12,043,615)	$4,572,455			
	Prevailing Flow	$56,624,124	$210,293,017	($148,785,171)			
	Total	$49,746,174	$198,249,402	($144,212,715)	$61,069,182	($205,281,897)	<0%
AP	Counter Flow	($15,705,393)	($22,253,308)	$5,193,355			
	Prevailing Flow	$173,787,290	$290,250,148	($101,474,035)			
	Total	$158,081,897	$267,996,840	($96,280,680)	$136,406,663	($232,687,343)	<0%
BGE	Counter Flow	$14,008,725	($2,300,744)	$17,517,695			
	Prevailing Flow	$43,572,235	$44,182,978	$3,147,280			
	Total	$57,580,960	$41,882,233	$20,664,975	$58,491,916	($37,826,940)	35.3%
ComEd	Counter Flow	($6,620,022)	($26,978,041)	$19,787,055			
	Prevailing Flow	$66,444,688	$112,919,688	($40,744,272)			
	Total	$59,824,666	$85,941,647	($20,957,217)	$91,907,660	($112,864,877)	<0%
DAY	Counter Flow	($1,357,607)	($1,611,412)	$136,714			
	Prevailing Flow	$1,574,798	$4,229,335	($2,518,714)			
	Total	$217,190	$2,617,923	($2,382,001)	$4,003,960	($6,385,961)	<0%
DLCO	Counter Flow	($1,828,474)	($6,299,121)	$4,312,944			
	Prevailing Flow	$6,295,118	$3,924,859	$2,913,201			
	Total	$4,466,644	($2,374,262)	$7,226,145	$7,870,868	($644,723)	91.8%
Dominion	Counter Flow	($10,555,463)	($22,925,830)	$11,459,977			
	Prevailing Flow	$145,761,931	$195,864,486	($37,530,865)			
	Total	$135,206,468	$172,938,657	($26,070,888)	$136,500,609	($162,571,497)	<0%
DPL	Counter Flow	($1,528,297)	($1,656,240)	($3,870)			
	Prevailing Flow	$18,227,014	$17,182,110	$2,616,950			
	Total	$16,698,717	$15,525,870	$2,613,080	$20,945,086	($18,332,007)	12.5%
JCPL	Counter Flow	($77,769)	($3,892,037)	$3,807,561			
	Prevailing Flow	$22,110,652	$26,200,020	($2,182,366)			
	Total	$22,032,883	$22,307,983	$1,625,195	$29,708,141	($28,082,946)	5.5%

Table 8-12 FTR congestion hedging by control zone: Planning period 2010 to 2011 through September 30, 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	($303,284)	($1,564,225)	$1,234,784			
	Prevailing Flow	$14,433,756	$6,886,119	$8,792,521			
	Total	$14,130,472	$5,321,894	$10,027,305	$9,545,624	$481,681	>100%
PECO	Counter Flow	$3,338,582	($4,309,257)	$7,935,786			
	Prevailing Flow	$25,471,491	$33,148,407	($5,480,049)			
	Total	$28,810,073	$28,839,150	$2,455,737	$3,318,756	($863,019)	74.0%
PENELEC	Counter Flow	($9,809,588)	($16,860,052)	$6,204,405			
	Prevailing Flow	$39,885,369	$58,326,682	($15,001,275)			
	Total	$30,075,781	$41,466,630	($8,796,870)	$49,089,661	($57,886,531)	<0%
Pepco	Counter Flow	($7,280,682)	($9,285,913)	$1,377,286			
	Prevailing Flow	$76,008,831	$109,850,417	($27,285,970)			
	Total	$68,728,149	$100,564,505	($25,908,684)	$42,180,918	($68,089,602)	<0%
PJM	Counter Flow	($4,935,772)	($13,012,368)	$7,650,895			
	Prevailing Flow	$2,169,351	$5,499,245	($3,142,792)			
	Total	($2,766,421)	($7,513,123)	$4,508,103	($1,356,301)	$5,864,404	<0%
PPL	Counter Flow	($8,201,507)	($7,116,230)	($1,792,642)			
	Prevailing Flow	$15,806,327	$21,555,087	($4,385,495)			
	Total	$7,604,819	$14,438,857	($6,178,137)	($754,523)	($5,423,613)	<0%
PSEG	Counter Flow	($249,467)	($4,611,006)	$4,340,022			
	Prevailing Flow	$31,949,847	$71,783,766	($37,078,305)			
	Total	$31,700,380	$67,172,760	($32,738,283)	$15,573,183	($48,311,466)	<0%
RECO	Counter Flow	($441,204)	($1,092,581)	$613,324			
	Prevailing Flow	$112,183	$159,314	($37,455)			
	Total	($329,020)	($933,267)	$575,869	$2,512,297	($1,936,428)	22.9%
Total	Counter Flow	($59,328,042)	($158,974,207)	$94,529,234			
	Prevailing Flow	$750,638,734	$1,219,939,727	($404,559,828)			
	Total	$691,310,693	$1,060,965,520	($310,030,594)	$685,258,696	($2,163,536,265)	<0%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-13 ARR and FTR congestion hedging by control zone: Planning period 2010 to 2011 through September 30, 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	$6,095,626	$9,500,860	$6,521,820	$9,074,666	$18,244,997	($9,170,331)	49.7%
AEP	$194,258,183	$49,746,174	$198,249,402	$45,754,955	$61,069,182	($15,314,227)	74.9%
AP	$308,392,416	$158,081,897	$267,996,840	$198,477,473	$136,406,663	$62,070,810	>100%
BGE	$33,678,997	$57,580,961	$41,882,233	$49,377,725	$58,491,916	($9,114,191)	84.4%
ComEd	$91,566,097	$59,824,665	$85,941,647	$65,449,115	$91,907,660	($26,458,545)	71.2%
DAY	$5,788,157	$217,191	$2,617,923	$3,387,425	$4,003,960	($616,535)	84.6%
DLCO	$5,052,309	$4,466,644	($2,374,262)	$11,893,215	$7,870,868	$4,022,347	>100%
Dominion	$176,445,497	$135,206,468	$172,938,657	$138,713,308	$136,500,609	$2,212,699	>100%
DPL	$12,437,921	$16,698,717	$15,525,870	$13,610,768	$20,945,086	($7,334,318)	65.0%
JCPL	$18,917,345	$22,032,883	$22,307,983	$18,642,245	$29,708,141	($11,065,896)	62.8%
Met-Ed	$13,935,697	$14,130,473	$5,321,894	$22,744,276	$9,545,624	$13,198,652	>100%
PECO	$23,365,352	$28,810,073	$28,839,150	$23,336,275	$3,318,756	$20,017,519	>100%
PENELEC	$23,704,470	$30,075,781	$41,466,630	$12,313,621	$49,089,661	($36,776,040)	25.1%
Pepco	$22,895,504	$68,728,149	$100,564,505	($8,940,852)	$42,180,918	($51,121,770)	<0%
PJM	$20,706,621	($2,766,421)	($7,513,123)	$25,453,323	($1,356,301)	$26,809,624	>100%
PPL	$27,383,200	$7,604,819	$14,438,857	$20,549,162	($754,523)	$21,303,685	>100%
PSEG	$44,042,280	$31,700,380	$67,172,760	$8,569,900	$15,573,183	($7,003,283)	55.0%
RECO	$93,249	($329,021)	($933,267)	$697,495	$2,512,297	($1,814,802)	27.8%
Total	$1,028,758,921	$691,310,692	$1,060,965,519	$659,104,094	$685,258,697	($26,154,603)	96.2%

Table 8-14 ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011[7] (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
2009/2010	$1,276,852,551	$879,858,494	$1,368,744,320	$787,966,725	$816,996,461	($29,029,736)	96.4%
2010/2011*	$344,031,671	$694,418,596	$365,350,969	$673,099,298	$685,258,696	($12,159,399)	98.2%

* Shows four months ended 30-Sep-10

ARRs and FTRs as a Hedge against Total Real Time Energy Charges

Table 8-15 ARRs and self-scheduled FTR credits as a hedge against energy charges by control zone: January through September 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	$8,634,718	$1,195,231	$9,829,949	$527,695,202	1.9%
AEP	$4,649,721	$133,653,035	$138,302,757	$4,190,577,520	3.3%
AP	$30,684,871	$273,542,176	$304,227,047	$1,704,464,574	17.8%
BGE	$29,243,268	$4,361,408	$33,604,676	$1,607,335,486	2.1%
ComEd	$33,531,737	$13,400,100	$46,931,838	$2,971,477,406	1.6%
DAY	$3,790,244	$1,891,871	$5,682,115	$543,382,247	1.0%
DLCO	$2,702,658	$488	$2,703,147	$458,418,907	0.6%
Dominion	$4,206,317	$196,551,333	$200,757,651	$4,266,751,071	4.7%
DPL	$10,626,726	$1,514,322	$12,141,048	$843,351,966	1.4%
JCPL	$16,979,554	$2,832,538	$19,812,092	$1,076,059,197	1.8%
Met-Ed	$4,481,390	$7,519,111	$12,000,502	$649,751,341	1.8%
PECO	$1,369,938	$31,065,806	$32,435,744	$1,794,748,851	1.8%
PENELEC	$17,421,713	$7,149,664	$24,571,377	$599,599,506	4.1%
Pepco	$15,928,001	$2,347,921	$18,275,922	$1,497,554,418	1.2%
PJM	$9,187,297	$2,523,457	$11,710,754	NA	NA
PPL	$7,223,644	$12,685,755	$19,909,399	$1,633,584,853	1.2%
PSEG	$47,561,669	$5,114,128	$52,675,797	$2,035,408,820	2.6%
RECO	$14,018	$0	$14,018	$67,588,582	0.0%
Total	$248,237,485	$697,348,346	$945,585,832	$26,508,109,834	3.6%

7 The FTR credits do not include after-the-fact adjustments. For the 2010 to 2011 planning period, the ARR credits were the total credits allocated to all ARR holders for the first four months (June through September 2010) of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the first four months of this planning period and the portion of Annual FTR Auction revenue distributed to the first four months.

Table 8-16 FTRs as a hedge against energy charges by control zone: January through September 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	$10,568,160	$11,102,958	($534,798)	$527,695,202	(0.1%)
AEP	$7,631,886	$1,163,057	$6,468,829	$4,190,577,520	0.2%
AP	($6,008,442)	($2,689,945)	($3,318,497)	$1,704,464,574	(0.2%)
BGE	$63,081,258	$27,337,795	$35,743,463	$1,607,335,486	2.2%
ComEd	$68,112,278	$25,479,151	$42,633,127	$2,971,477,406	1.4%
DAY	($993,966)	($536,375)	($457,591)	$543,382,247	(0.1%)
DLCO	$13,566,110	($3,131,664)	$16,697,774	$458,418,907	3.6%
Dominion	$31,149,173	$11,578,133	$19,571,039	$4,266,751,071	0.5%
DPL	$22,177,842	$19,813,894	$2,363,948	$843,351,966	0.3%
JCPL	$20,383,824	$22,628,556	($2,244,732)	$1,076,059,197	(0.2%)
Met-Ed	$15,428,397	$3,706,206	$11,722,192	$649,751,341	1.8%
PECO	$11,199,046	$5,081,156	$6,117,890	$1,794,748,851	0.3%
PENELEC	$59,140,498	$33,902,596	$25,237,902	$599,599,506	4.2%
Pepco	$115,654,962	$78,112,276	$37,542,686	$1,497,554,418	2.5%
PJM	($6,824,459)	($6,952,384)	$127,925	NA	NA
PPL	$6,690,024	$5,894,175	$795,849	$1,633,584,853	0.0%
PSEG	$58,549,743	$65,751,706	($7,201,963)	$2,035,408,820	(0.4%)
RECO	($1,018,955)	($1,665,243)	$646,288	$67,588,582	1.0%
Total	$488,487,379	$296,576,048	$191,911,331	$26,508,109,834	0.7%

Table 8-17 ARRs and FTRs as a hedge against energy charges by control zone: January through September 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	$9,829,949	($534,798)	$9,295,151	$527,695,202	1.8%
AEP	$138,302,757	$6,468,829	$144,771,585	$4,190,577,520	3.5%
AP	$304,227,047	($3,318,497)	$300,908,550	$1,704,464,574	17.7%
BGE	$33,604,676	$35,743,463	$69,348,139	$1,607,335,486	4.3%
ComEd	$46,931,838	$42,633,127	$89,564,965	$2,971,477,406	3.0%
DAY	$5,682,115	($457,591)	$5,224,524	$543,382,247	1.0%
DLCO	$2,703,147	$16,697,774	$19,400,921	$458,418,907	4.2%
Dominion	$200,757,651	$19,571,039	$220,328,690	$4,266,751,071	5.2%
DPL	$12,141,048	$2,363,948	$14,504,996	$843,351,966	1.7%
JCPL	$19,812,092	($2,244,732)	$17,567,360	$1,076,059,197	1.6%
Met-Ed	$12,000,502	$11,722,192	$23,722,693	$649,751,341	3.7%
PECO	$32,435,744	$6,117,890	$38,553,634	$1,794,748,851	2.1%
PENELEC	$24,571,377	$25,237,902	$49,809,279	$599,599,506	8.3%
Pepco	$18,275,922	$37,542,686	$55,818,608	$1,497,554,418	3.7%
PJM	$11,710,754	$127,925	$11,838,679	NA	NA
PPL	$19,909,399	$795,849	$20,705,248	$1,633,584,853	1.3%
PSEG	$52,675,797	($7,201,963)	$45,473,834	$2,035,408,820	2.2%
RECO	$14,018	$646,288	$660,306	$67,588,582	1.0%
Total	$945,585,832	$191,911,331	$1,137,497,162	$26,508,109,834	4.3%