2009 Quarterly State of the Market Report for PJM:
January through September

Monitoring Analytics, LLC
Independent Market Monitor for PJM

November 13, 2009

PREFACE

PJM has filed to amend Attachment M (PJM Market Monitoring Plan) to the PJM Open Access Transmission Tariff in order to provide, consistent with Order No. 719,[1] a requirement that the Market Monitoring Unit (MMU) "report on aggregate market performance on no less than a quarterly basis to Commission staff, to staff of interested state commissions, and to the management and board of directors of the RTOs or ISOs."[2] Upon acceptance by the Commission, Section VI.A of Attachment M would read:

> 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. The annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[3]

Although the tariff language is not yet approved,[4] Monitoring Analytics, LLC, which serves as the Market Monitoring Unit defined in Attachment M, has determined to meet the requirement for a quarterly report on the basis of the requirement established in Order No. 719. Accordingly, the MMU submits this *2009 Quarterly State of the Market Report for PJM: January through September*.

1 125 FERC ¶61,071 at PP 395, 413–19 (2008), *order on reh'g*, 128 FERC ¶61,059.
2 125 FERC ¶61,071 at PP 395, 413–19 (2008), *order on reh'g*, 128 FERC ¶61,059.
3 PJM OATT, "Attachment M: PJM Market Monitoring Plan," Sixth Revised Sheet No. 452–452A (proposed to become effective June 29, 2009).
4 On May 27, 2009, Monitoring Analytics filed a Protest and Compliance Proposal of the Independent Market Monitor for PJM in FERC Docket No. ER09-1036. The Compliance Proposal addressed issues related to the independence of the market monitoring function but contained no proposed modifications of the provision quoted above.

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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, 2009, had installed generating capacity of 167,269 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.[1] As part of that function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

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]

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 includes the price of energy, capacity, ancillary services, transmission service, administrative fees, regulatory support fees and uplift charges. This total price is an average price and actual prices vary by location.

Table 1-1 Total price per MWh: January through September 2009 (New Table)

Category	$/MWh	Percent
Load Weighted Energy	$39.57	73.4%
Capacity	$9.03	16.8%
Transmission Service	$3.54	6.6%
Operating Reserves (Uplift)	$0.44	0.8%
Regulation	$0.33	0.6%
Reactive	$0.32	0.6%
PJM Administrative	$0.31	0.6%
Transmission Cost Recovery	$0.18	0.3%
Transmission Owner (Schedule 1A)	$0.08	0.1%
Synchronized Reserves	$0.03	0.1%
Black Start Services	$0.02	0.0%
RTO Startup and Expansion	$0.01	0.0%
NERC/RFC	$0.01	0.0%
Load Response	$0.00	0.0%
Total	$53.87	100.0%

1 See the *2008 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.
2 See also the *2008 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."
3 Analysis of 2009 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 *2008 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Conclusions

This report assesses the competitiveness of the markets managed by PJM during the first nine months of 2009, 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 concludes that in the first nine months of 2009:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;
- The Regulation Market results were competitive;
- The Synchronized Reserve Market results were competitive;
- The Day Ahead Scheduling Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

Recommendations

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

> PJM is responsible for proposing for approval by the Commission, consistent with tariff procedures and applicable law, changes to the design of the PJM Markets. If the Market Monitoring Unit detects a design flaw or other problem with the PJM Markets, the Market Monitoring Unit may initiate and propose, through the appropriate stakeholder processes, changes to the design of such market. In support of this function, the Market Monitoring Unit may engage in discussions with stakeholders, State Commissions, PJM Management, or the PJM Board; participate in PJM stakeholder meetings or working groups regarding market design matters; publish proposals, reports or studies on such market design issues; and make filings with the Commission on market design issues.[4]

4 PJM OATT Attachment M § IV.D.

In addition, the PJM Market Monitoring Plan provides, in describing the State of the Market Report: "In such reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview."[5] Pursuant to its explicit mandate under the PJM Market Monitoring Plan, the MMU recommends retention of key market rules, specific enhancements to those rules and implementation of new rules that are required for continued competitive results in PJM markets and for continued improvements in the functioning of PJM markets. The MMU's recommendations from the *2008 State of the Market Report for PJM* remain recommendations.

In this *2009 Quarterly State of the Market Report for PJM: January through September*, the MMU makes specific recommendations, some of which were included in the *2009 Quarterly State of the Market Report for PJM: January through June*. Further details can be found in the referenced sections.

New Recommendations in Quarter Three

- Section 3, Energy Market Part 2, at "Modifications to Scarcity Pricing" (page 47):[6]
    - If there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues.
    - The current single scarcity price signal should be replaced by locational signals.
    - The objective should be to create a system that recognizes scarcity in needed reserves, that redispatches units to maintain needed reserves and to meet the need for energy, and that provides market signals consistent with this redispatch and with any failure to maintain needed reserves.

5 PJM OATT Attachment M § VI.A. *See also* Order No. 719 at P 357 ("[W]e do expect the MMU to advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule and tariff changes. Likewise, in the event an RTO or ISO files for a proposed tariff change with which the MMU disagrees, we expect the RTO or ISO to inform the Commission of that disagreement, although not necessarily to include a written proposal with its filing."), codified at 18 C.F.R. § 35.28 (g)(3)(ii)(A) ("The Market Monitoring Unit must perform the following core functions: (A) Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the Commission-Approved independent system operator or regional transmission organizations, to the Commission's Office of Energy Market Regulation staff and to other interested entities such as state commissions and market participants").

6 For ease of reference, all the recommendations from the quarterly state of the market reports related to scarcity are listed here, including those from Quarter Two and Quarter Three.

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- PJM needs to develop better measurements of available primary reserves prior to implementing a resource constraint based scarcity pricing mechanism as current measures are not adequate.

- Any scarcity pricing mechanism should also include an explicit, transparent set of rules governing the recall of energy produced by capacity resources and the defined conditions under which such recalls will occur.

- To avoid market power, the provision of reserves must continue to be based on unit characteristics included in a participant's energy offers, not on the basis of separate offers to provide reserves.

- The reserve penalty factor curve methodology also requires a mechanism to eliminate the effect of non-market administrative emergency measures used during scarcity situations.

- Section 4, Interchange Transactions, at "Loop Flows at PJM's Northern Interfaces" (page 78): The MMU recommends that a change in the interface pricing methodology be addressed directly. The MMU recommends that the parties consider the uniform adoption of a Generation Control Area (GCA) to Load Control Area (LCA) pricing methodology, similar to that used by PJM, to set transaction prices based on the actual flow of energy from source to sink. With the appropriate pricing, the incentive for market participants to schedule around specific RTOs/ISOs would be eliminated.

Continuing Recommendations from Quarter Two

- Section 2, Energy Market Part 1, at "DSR" (page 7): 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.

- Section 4, Interchange Transactions, at "Up-To Congestion" (page 77): The MMU recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

- Section 4, Interchange Transactions, at "Data Required for Full Loop Flow Analysis" (page 79): The MMU recommends that PJM and the Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would contribute to the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impact data, actual flowgate flow data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

- Section 4, Interchange Transactions, at "Conclusion" (page 80): In order to manage interactions with non market areas, PJM has entered into coordination agreements with other balancing authorities as a first step. … PJM also entered into agreements with specific balancing authorities for separate interface pricing that have been questioned with respect to transparency and equal access. PJM needs to ensure that such pricing is transparent, accurately reflects actual LMP impacts on PJM, and that all participants have access to the defined pricing when in the same position. The goal of such pricing agreements should be to replicate LMP price signals that reflect the actual loads and the actual dispatch of units.

- Section 5, Capacity market, at "Conclusion, Market Design" (page 99): The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

- Section 5, Capacity Market, at "Conclusion, Market Design" (page 99): A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

- Section 5, Capacity Market, at "Conclusion, Market Power" (page 101): The performance incentives in the RPM Capacity Market design need to be strengthened.

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- Section 6, Ancillary Services, at “Black Start Services” (page 114): 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.

- Section 6, Ancillary Services, at “Conclusion” (page 115): The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test.

- Section 8, Financial Transmission and Auction Revenue Rights, at “Conclusion” (page 158): 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.

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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 the first nine months of 2009, 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 2009.

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.

Overview

Market Structure

- **Supply.** During the July through September 2009 quarter, the PJM Energy Market received an hourly average of 152,314 MW in supply offers.[3] The third quarter 2009 average supply offers were 338 MW higher than the third quarter 2008 average supply of 151,976 MW.

- **Demand.** The PJM system peak load in the third quarter 2009 was 126,805 MW in the hour ended 1700 EPT on August 10, 2009, while the PJM peak load in the third quarter 2008 was 129,481 in the hour ended 1700 on July 18, 2008.[4] The 2009 third quarter peak load was 2,676 MW, or 2.1 percent, lower than the third quarter 2008 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.

- **Local Market Structure and Offer Capping.** Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in January through September 2009. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours were 0.1 percent of all hours in the first nine months of 2009, down from

1 Analysis of the first nine months of 2009 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 *2008 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 August 1, 2008).

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 *2009 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 *2008 State of the Market Report for PJM*, Appendix M, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

0.2 percent in 2008. In the Real-Time Energy Market offer-capped unit hours fell from 1.0 percent in 2008 to 0.5 percent of all hours in the first nine months of 2009.

- **Local Market Structure.** A summary of the results of PJM's application of the three pivotal supplier test is presented for all constraints which occurred for 75 or more hours during the first three quarters of calendar year 2009. During the first three quarters of 2009 (January 1, 2009 through September 30, 2009), the PSEG, AP, AEP, PENELEC, Dominion, AECO, DLCO, ComEd, PECO, BGE and Pepco Control Zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to ensure that owners are not subject to offer capping when the market structure is competitive and to offer cap only pivotal owners when the market structure is noncompetitive.

Market Conduct

- **Markup.** The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. For marginal units, the markup index is a measure of market power. A positive markup by marginal units will result in a difference between the observed market price and the competitive market price. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[5] The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.[6] In the real time market, the average markup index from January to September 2009 was -0.07 with a monthly average maximum of -0.04 in January and a monthly average minimum of -0.11 in April. In the day ahead market, the average markup index from January to September 2009 was 0.00 with a monthly average maximum of 0.02 in February and a minimum of -0.02 in April. 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.

5 A marginal unit's offer price does not always correspond to the LMP at the unit's bus. As a general matter the LMP at a bus is equal to the unit's offer. However in practice, actual, security-constrained dispatch can create conditions where the LMP at a marginal unit bus does not correspond to the unit's offer. The marginal unit's offer price and associated cost are used when calculating measures of participant behavior or conduct, like markup.

6 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

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 was -$3.67 per MWh, or -9.3 percent. Coal steam units contributed -$3.04, or 82.9 percent, to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed -$0.68 or 18.6 percent to the total markup component of LMP. The markup was -$3.24 per MWh during peak hours and -$4.14 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP was -$0.50 per MWh, or -1.3 percent. Coal steam units contributed -$0.52 or 103.5 percent to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed -$0.03 or 6.9 percent to the total markup component of LMP. The markup was $0.31 per MWh during peak hours and -$1.39 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 decreased in the first nine months of 2009 by 4.5 percent from the first nine months of 2008, falling from 80,611 MW to 76,956 MW. PJM day-ahead load decreased in the first nine months of 2009 by 8.0 percent from the first nine months of 2008, falling from 97,505 MW to 89,680 MW.

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- **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. For example, overall average prices subsume congestion (price differences at a point in time) and price differences over time.

  PJM Real-Time Energy Market prices decreased in the first nine months of 2009 compared to the first nine months of 2008. The system simple average LMP was 48.0 percent lower in the first nine months of 2009 than in the first nine months of 2008, \$37.42 per MWh versus \$71.94 per MWh. The load-weighted LMP was 48.8 percent lower in the first nine months of 2009 than in the first nine months of 2008, \$39.57 per MWh versus \$77.27 per MWh. The fuel cost adjusted, load-weighted, average LMP was 11.2 percent lower in the first nine months of 2009 than the load-weighted, average LMP in the first nine months of 2008, \$68.61 per MWh compared to \$77.27 per MWh. In other words, if fuel costs for the first nine months of 2009 had been the same as for the first nine months of 2008, the 2009 load-weighted LMP would have been higher, \$68.61 per MWh, instead of the observed \$39.57 per MWh, and 11.2 percent lower than the load-weighted average LMP for the first nine months of 2008. Fuel costs and lower loads in the first nine months of 2009 contributed to downward pressure on LMP.

  PJM Day-Ahead Energy Market prices decreased in the first nine months of 2009 compared to the first nine months of 2008. The system simple average LMP was 47.7 percent lower in the first nine months of 2009 than in the first nine months of 2008, \$37.35 per MWh versus \$71.43 per MWh. The load-weighted LMP was 48.2 percent lower in the first nine months of 2009 than in the first nine months of 2008, \$39.35 per MWh versus \$75.96 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 single PJM parent company that serves load, its load can be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first nine months of 2009, 13.0 percent of real-time load was supplied by bilateral contracts, 16.6 percent by spot market purchases and 70.4 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased by 1.7 percentage points, reliance on spot supply decreased by 3.5 percentage points, and reliance on self-supply increased by 5.2 percentage points in January through September 2009.

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. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. The current approach can and has resulted in payments when the customer has taken no action to respond to market prices. 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.

  Total demand-side response resources available in PJM on August 10, 2009 (the peak day in January through September 2009), were 5,129.8 MW eligible for capacity and emergency energy credits and 2,164.5 MW eligible for capacity payments from the Emergency Load-Response Program and 2,486.6 MW from the Economic Load-Response Program.

  Participation in the Economic Load-Response Program, in terms of settlement days submitted and active customers, decreased significantly in the first six months of 2009 compared to the same period in 2008, resulting from a combination of program verification improvements implemented in 2008, and lower price levels. However, settlement days submitted have increased significantly from June to August, showing participation levels comparable to the same period in 2008. Participation in the Load Management (LM) Program has increased significantly, both in Demand Response offering into RPM Auctions and ILR available in delivery year 2009/2010.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the first nine months of 2009, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply increased by about 338 MW when comparing the third quarter of 2009 to the third quarter of 2008 while aggregate peak load decreased by 2,676 MW, modifying the general supply demand balance from 2008 with a corresponding impact on Energy Market prices. Overall load was also lower than in third quarter 2008. Market concentration levels remained moderate and average markup was negative. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

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

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests.

The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

Energy Market results for the first nine months of 2009 generally reflected supply-demand fundamentals. Lower prices in the Energy Market were the result of lower fuel costs and of lower demand. PJM Real-Time, load-weighted, average LMP for the first nine months of 2009 was $39.57, or 48.8 percent lower than the load-weighted, average LMP for the first nine months of 2008, which was $77.27. The real-time, fuel-cost-adjusted, load-weighted, average LMP in the first nine months of 2009 was $68.61, or 11.2 percent lower than the load-weighted, average LMP in the first nine months of 2008, which was $77.27. In other words, if fuel costs for the first nine months of 2009 had been the same as for the first nine months of 2008, the 2009 load-weighted LMP would have been higher, $68.61 per MWh, instead of the observed $39.57 per MWh, and 11.2 percent lower than the load-weighted average LMP for the first nine months of 2008. Lower fuel prices in 2009 resulted in lower energy prices in 2009 than would have occurred if fuel prices had remained at 2008 levels. Lower demand also contributed to lower prices.

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 2009.

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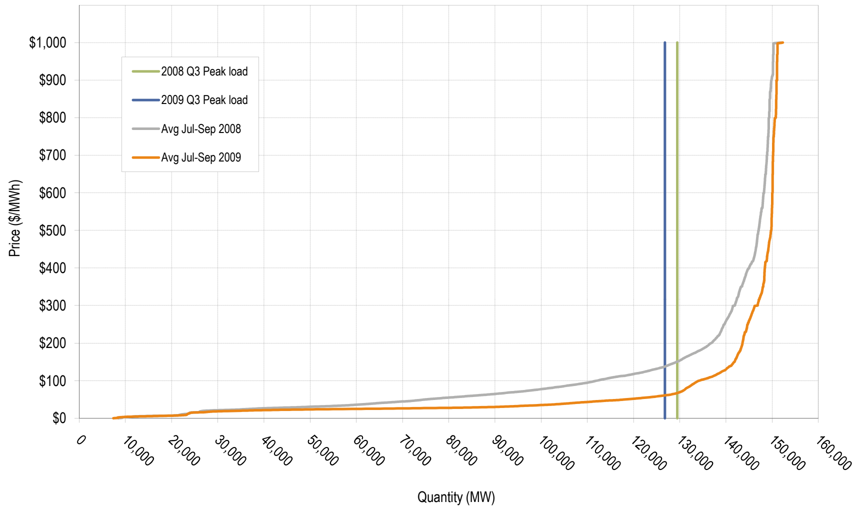
Market Structure

Supply

Figure 2-1 Average PJM aggregate supply curves: July through September 2008 and 2009 (See 2008 SOM, Figure 2-1)

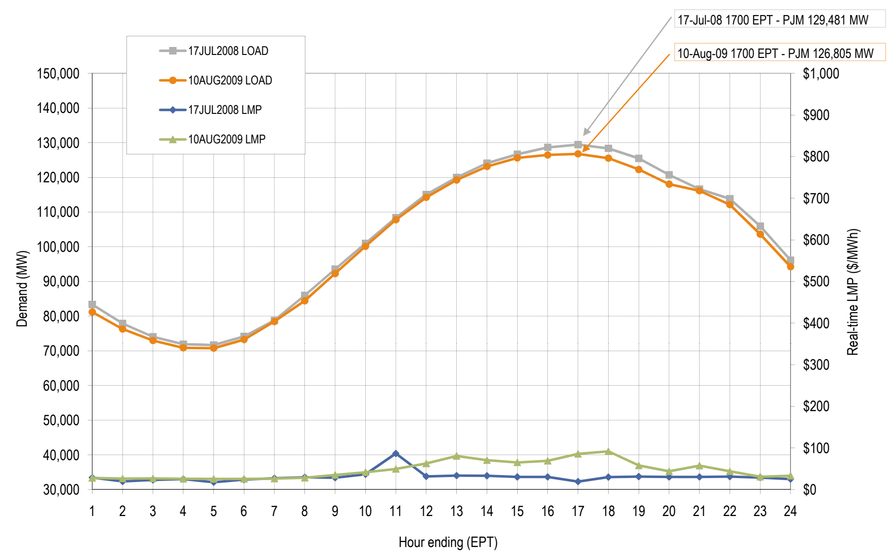


Demand

Table 2-1 Actual PJM footprint quarter three peak loads: 2005 to 2009 (See 2008 SOM, Table 2-2)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)
2005	26-Jul-05	1600	133,761	NA
2006	02-Aug-06	1700	144,644	10,883
2007	08-Aug-07	1600	139,428	(5,216)
2008	17-Jul-08	1700	129,481	(9,947)
2009	10-Aug-09	1700	126,805	(2,676)

Figure 2-2 PJM quarter three peak-load comparison: Monday, August 10, 2009, and Friday, July 18, 2008 (See 2008 SOM, Figure 2-2)



Market Concentration

PJM HHI Results

Table 2-2 PJM hourly Energy Market HHI: January through September 2009 (See 2008 SOM, Table 2-3)

	Hourly Market HHI
Average	1231
Minimum	935
Maximum	1628
Highest market share (One hour)	32%
Highest market share (All hours)	22%
# Hours	6551
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Local Market Structure and Offer Capping

Table 2-3 Annual offer-capping statistics: Calendar years 2005 through September 2009 (See 2008 SOM, Table 2-5)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2005	1.8%	0.4%	0.2%	0.1%
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	0.5%	0.1%	0.1%	0.0%

Table 2-4 Offer-capped unit statistics: January through September 2009 (See 2008 SOM, Table 2-6)

	2009 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	1	5
80% and < 90%	0	0	0	1	1	16
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	0	2	8
60% and < 70%	0	0	2	0	0	28
50% and < 60%	0	0	0	1	0	18
25% and < 50%	0	0	0	0	1	51
10% and < 25%	2	0	1	0	2	53

Local Market Structure

Table 2-5 Three pivotal supplier results summary for regional constraints: January through September 2009[7] (See 2008 SOM, Table 2-7)

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	657	635	97%	48	7%
	Off Peak	165	158	96%	20	12%
AP South	Peak	1,236	689	56%	803	65%
	Off Peak	566	310	55%	376	66%
Bedington - Black Oak	Peak	243	216	89%	117	48%
	Off Peak	110	84	76%	41	37%
Kammer	Peak	3,786	3,508	93%	624	16%
	Off Peak	4,145	3,619	87%	1,064	26%
West	Peak	332	321	97%	30	9%
	Off Peak	59	59	100%	0	0%

7 The number of tests with one or more failing owners plus the number of tests with one or more passing owners can exceed the total number of tests applied. A single test can result in one or more owners passing and one or more owners failing. In such a case, the interval would be counted as including one or more passing owners and one or more failing owners.

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Table 2-6 Three pivotal supplier test details for regional constraints: January through September 2009[8] (See 2008 SOM, Table 2-8)

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	61	347	19	19	1
	Off Peak	54	314	18	17	1
AP South	Peak	97	293	12	6	6
	Off Peak	102	303	11	5	6
Bedington - Black Oak	Peak	67	193	12	9	3
	Off Peak	57	214	13	9	4
Kammer	Peak	51	249	21	19	2
	Off Peak	52	221	17	14	3
West	Peak	125	627	22	21	1
	Off Peak	121	738	18	18	0

Table 2-7 Three pivotal supplier results summary for the East and Central interfaces: January through September 2009[9] (See 2008 SOM, Table 2-13)

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
Central	Peak	17	17	100%	0	0%
	Off Peak	9	9	100%	0	0%
East	Peak	0	NA	NA	NA	NA
	Off Peak	0	NA	NA	NA	NA

8 The average number of owners passing and the average number of owners failing are rounded to the nearest whole number and may not sum to the average number of owners, also rounded to the nearest whole number.

9 The East Interface constraint did not occur from January through September 2009. The Central Interface constraint occurred for eight hours from January through September 2009.

Table 2-8 Three pivotal supplier test details for the East and Central interfaces: January through September 2009 (See 2008 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
Central	Peak	61	565	19	19	0
	Off Peak	84	884	19	19	0
East	Peak	NA	NA	NA	NA	NA
	Off Peak	NA	NA	NA	NA	NA

Table 2-9 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: January through September 2009 (See 2008 SOM, Table 2-17)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Athenia - Saddlebrook	Peak	333	8	2%	329	99%
	Off Peak	135	5	4%	134	99%
Brunswick - Edison	Peak	226	6	3%	226	100%
	Off Peak	84	0	0%	84	100%
Plainsboro - Trenton	Peak	592	0	0%	592	100%
	Off Peak	13	0	0%	13	100%

Table 2-10 Three pivotal supplier test details for constraints located in the PSEG Control Zone: January through September 2009 (See 2008 SOM, Table 2-18)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	13	38	3	0	3
	Off Peak	10	42	3	0	3
Brunswick - Edison	Peak	8	89	1	0	1
	Off Peak	6	65	1	0	1
Plainsboro - Trenton	Peak	9	122	1	0	1
	Off Peak	7	141	1	0	1

Table 2-11 Three pivotal supplier results summary for constraints located in the AP Control Zone: January through September 2009 (See 2008 SOM, Table 2-19)

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
Bedington	Peak	895	125	14%	895	100%
	Off Peak	333	11	3%	333	100%
Elrama - Mitchell	Peak	649	357	55%	383	59%
	Off Peak	278	184	66%	123	44%
Mount Storm - Pruntytown	Peak	461	331	72%	248	54%
	Off Peak	254	165	65%	143	56%
Sammis - Wylie Ridge	Peak	346	245	71%	154	45%
	Off Peak	504	365	72%	239	47%
Tiltonsville - Windsor	Peak	1,179	1	0%	1,178	100%
	Off Peak	217	0	0%	217	100%
Wylie Ridge	Peak	695	577	83%	182	26%
	Off Peak	945	653	69%	378	40%

Table 2-12 Three pivotal supplier test details for constraints located in the AP Control Zone: January through September 2009 (See 2008 SOM, Table 2-20)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	31	5	3	0	3
	Off Peak	38	4	3	0	3
Elrama - Mitchell	Peak	20	65	12	9	4
	Off Peak	16	62	12	9	2
Mount Storm - Pruntytown	Peak	85	306	12	8	4
	Off Peak	97	273	11	6	4
Sammis - Wylie Ridge	Peak	44	118	20	13	7
	Off Peak	56	128	17	11	6
Tiltonsville - Windsor	Peak	11	6	2	0	2
	Off Peak	7	7	2	0	2
Wylie Ridge	Peak	36	147	17	15	2
	Off Peak	37	141	14	12	2

Table 2-13 Three pivotal supplier results summary for constraints located in the AEP Control Zone: January through September 2009 (See 2008 SOM, Table 2-21)

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
Cloverdale - Lexington	Peak	306	164	54%	207	68%
	Off Peak	1,504	838	56%	1,009	67%
Kammer - Ormet	Peak	1,439	28	2%	1,411	98%
	Off Peak	1,965	0	0%	1,965	100%
Kanawha River - Kincaid	Peak	318	0	0%	318	100%
	Off Peak	240	0	0%	240	100%
Poston - Postel Tap	Peak	461	0	0%	461	100%
	Off Peak	39	0	0%	39	100%
Ruth - Turner	Peak	1,353	0	0%	1,353	100%
	Off Peak	1,480	0	0%	1,480	100%

Table 2-14 Three pivotal supplier test details for constraints located in the AEP Control Zone: January through September 2009 (See 2008 SOM, Table 2-22)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cloverdale - Lexington	Peak	76	219	16	7	9
	Off Peak	70	190	14	7	8
Kammer - Ormet	Peak	18	21	1	0	1
	Off Peak	22	31	1	0	1
Kanawha River - Kincaid	Peak	12	4	1	0	1
	Off Peak	9	5	1	0	1
Poston - Postel Tap	Peak	8	14	1	0	1
	Off Peak	11	18	1	0	1
Ruth - Turner	Peak	18	3	1	0	1
	Off Peak	20	3	1	0	1

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Table 2-15 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: January through September 2009 (See 2008 SOM, Table 2-25)

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
Homer City - Shelocta	Peak	540	22	4%	529	98%
	Off Peak	140	3	2%	140	100%

Table 2-16 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: January through September 2009 (See 2008 SOM, Table 2-26)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Homer City - Shelocta	Peak	25	59	4	0	4
	Off Peak	41	55	5	0	5

Table 2-17 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: January through September 2009 (See 2008 SOM, Table 2-27)

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	919	0	0%	919	100%
	Off Peak	125	0	0%	125	100%

Table 2-18 Three pivotal supplier test details for constraints located in the Dominion Control Zone: January through September 2009 (See 2008 SOM, Table 2-28)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	4	3	1	0	1
	Off Peak	4	2	1	0	1

Table 2-19 Three pivotal supplier results summary for constraints located in the AECO Control Zone: January through September 2009 (See 2008 SOM, Table 2-31)

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
Absecon - Lewis	Peak	61	0	0%	61	100%
	Off Peak	16	0	0%	16	100%

Table 2-20 Three pivotal supplier test details for constraints located in the AECO Control Zone: January through September 2009 (See 2008 SOM, Table 2-32)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Absecon - Lewis	Peak	8	19	1	0	1
	Off Peak	7	27	1	0	1

Table 2-21 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: January through September 2009 (See 2008 SOM, Table 2-33)

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
Logans Ferry - Universal	Peak	963	0	0%	963	100%
	Off Peak	197	0	0%	197	100%

Table 2-22 Three pivotal supplier test details for constraints located in the DLCO Control Zone: January through September 2009 (See 2008 SOM, Table 2-34)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Logans Ferry - Universal	Peak	7	42	1	0	1
	Off Peak	6	37	1	0	1

Table 2-23 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: January through September 2009 (See 2008 SOM, Table 2-35)

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
Crete - East Frankfurt	Peak	102	21	21%	98	96%
	Off Peak	1,250	73	6%	1,225	98%
Electric Jct - Nelson	Peak	262	5	2%	261	100%
	Off Peak	740	1	0%	740	100%
Pleasant Valley - Belvidere	Peak	436	0	0%	436	100%
	Off Peak	921	0	0%	921	100%

Table 2-24 Three pivotal supplier test details for constraints located in the ComEd Control Zone: January through September 2009 (See 2008 SOM, Table 2-36)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Crete - East Frankfurt	Peak	33	113	5	1	4
	Off Peak	35	48	4	0	4
Electric Jct - Nelson	Peak	31	15	3	0	3
	Off Peak	35	4	2	0	2
Pleasant Valley - Belvidere	Peak	11	1	1	0	1
	Off Peak	12	0	1	0	1

Table 2-25 Three pivotal supplier results summary for constraints located in the PECO Control Zone: January through September, 2009 (See 2008 SOM, Table 2-37)

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
Emilie	Peak	1,374	35	3%	1,365	99%
	Off Peak	712	3	0%	712	100%

Table 2-26 Three pivotal supplier test details for constraints located in the PECO Control Zone: January through September 2009 (See 2008 SOM, Table 2-38)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Emilie	Peak	15	59	4	0	4
	Off Peak	14	83	4	0	4

Table 2-27 Three pivotal supplier results summary for constraints located in the BGE Control Zone: January through September 2009 (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
Graceton - Raphael Road	Peak	489	447	91%	76	16%
	Off Peak	250	225	90%	50	20%

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Table 2-28 Three pivotal supplier test details for constraints located in the BGE Control Zone: January through September 2009 (New Table)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Graceton - Raphael Road	Peak	30	116	19	18	2
	Off Peak	41	142	21	19	2

Table 2-29 Three pivotal supplier results summary for constraints located in the Pepco Control Zone: January through September 2009 (See 2008 SOM, Table 2-39)

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
Buzzard - Ritchie	Peak	366	0	0%	366	100%
	Off Peak	NA	NA	NA	NA	NA

Table 2-30 Three pivotal supplier test details for constraints located in the Pepco Control Zone: January through September 2009 (See 2008 SOM, Table 2-40)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Buzzard - Ritchie	Peak	6	26	2	0	2
	Off Peak	NA	NA	NA	NA	NA

Market Performance: Markup

Real-Time Markup

Table 2-31 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through September 2009 (See 2007 SOM, Table 2-31)

Company	Percent of Price
1	17%
2	14%
3	9%
4	8%
5	8%
6	6%
7	6%
8	4%
9	3%
Other (46 companies)	27%

Table 2-32 Type of fuel used (By real-time marginal units): January through September 2009 (See 2007 SOM, Table 2-32)

Fuel Type	Percent on the Margin
Coal	73%
Natural Gas	20%
Petroleum	5%
Landfill Gas	1%
Interface	1%
Misc	0%

Figure 2-3 Real-time, LMP contribution and load-weighted, unit markup index: January through September 2009 (See 2007 SOM, Figure 2-4)

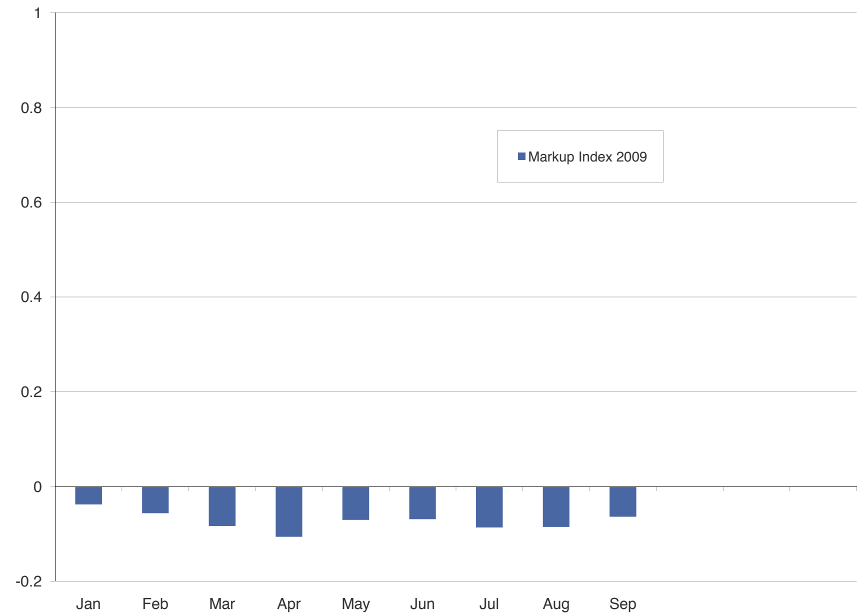

Table 2-33 Average, real-time marginal unit markup index (By price category): January through September 2009 (See 2007 SOM, Table 2-34)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($3.41)
$25 to $50	(0.11)	($5.50)
$50 to $75	(0.02)	($2.97)
$75 to $100	0.04	$2.69
$100 to $125	0.08	$6.70
$125 to $150	0.05	$4.96
> $150	0.04	$7.80

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

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($3.04)	82.9%
Gas	CC	($0.68)	18.6%
Gas	CT	$0.02	(0.5%)
Gas	Diesel	$0.00	(0.1%)
Gas	Steam	$0.01	(0.3%)
Interface	Interface	($0.00)	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	($0.02)	0.5%
Oil	CC	($0.00)	0.0%
Oil	CT	$0.04	(1.1%)
Oil	Diesel	($0.02)	0.4%
Oil	Steam	$0.02	(0.5%)
Uranium	Steam	($0.00)	0.0%
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.00	(0.0%)
Total		($3.67)	100.0%

Table 2-35 Monthly markup components of load-weighted LMP: January through September 2009 (See 2007 SOM, Table 2-35)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.53)	($0.49)	($2.52)
Feb	($1.97)	($1.65)	($2.31)
Mar	($4.24)	($4.73)	($3.73)
Apr	($4.78)	($3.78)	($5.96)
May	($3.23)	($2.75)	($3.68)
Jun	($3.33)	($1.99)	($4.98)
Jul	($3.61)	($3.67)	($3.54)
Aug	($5.84)	($3.88)	($7.93)
Sep	($4.73)	($6.56)	($2.67)
2009 (Jan - Sep)	($3.67)	($3.24)	($4.14)

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Table 2-36 Average real-time zonal markup component: January through September 2009 (See 2007 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($3.66)	($3.43)	($3.90)
AEP	($4.29)	($3.87)	($4.73)
AP	($3.17)	($2.48)	($3.91)
BGE	($3.49)	($2.71)	($4.33)
ComEd	($4.28)	($4.04)	($4.55)
DAY	($4.61)	($4.19)	($5.08)
DLCO	($4.45)	($3.98)	($4.98)
Dominion	($2.98)	($2.23)	($3.79)
DPL	($2.87)	($3.06)	($2.68)
JCPL	($3.52)	($3.17)	($3.93)
Met-Ed	($3.00)	($3.05)	($2.94)
PECO	($3.45)	($3.23)	($3.68)
PENELEC	($3.59)	($3.30)	($3.91)
Pepco	($3.16)	($2.35)	($4.05)
PPL	($3.38)	($3.11)	($3.67)
PSEG	($3.53)	($3.18)	($3.93)
RECO	($3.54)	($3.12)	($4.04)

Table 2-37 Average real-time markup component (By price category): January through September 2009 (See 2008 SOM, Table 2-41)

	Average Markup Component	Frequency
Below $20	($0.29)	5.1%
$20 to $40	($5.49)	73.7%
$40 to $60	($3.44)	23.6%
$60 to $80	$0.72	5.7%
$80 to $100	$9.01	2.3%
$100 to $120	$0.76	0.7%
$120 to $140	$40.38	0.4%
$140 to $160	$13.87	0.2%
Above $160	$52.56	0.2%

Day-Ahead Markup

Table 2-38 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through September 2009 (See 2007 SOM, Table 2-31)

Company	Percent of Price
1	33%
2	9%
3	6%
4	5%
5	5%
6	4%
7	3%
8	3%
9	2%
Other (118 companies)	30%

Table 2-39 Day-ahead marginal resources by type/fuel: January through September 2009 (See 2007 SOM, Table 2-32)

Type/Fuel	Percent on the Margin
Transaction	35%
DEC	30%
INC	19%
Coal	12%
Natural gas	3%
Price sensitive demand	1%
Petroleum	0%
Wind	0%
Misc	0%
Landfill gas	0%

Figure 2-4 Day-ahead, LMP contribution and load-weighted unit markup index: January through September 2009 (See 2007 SOM, Figure 2-4)

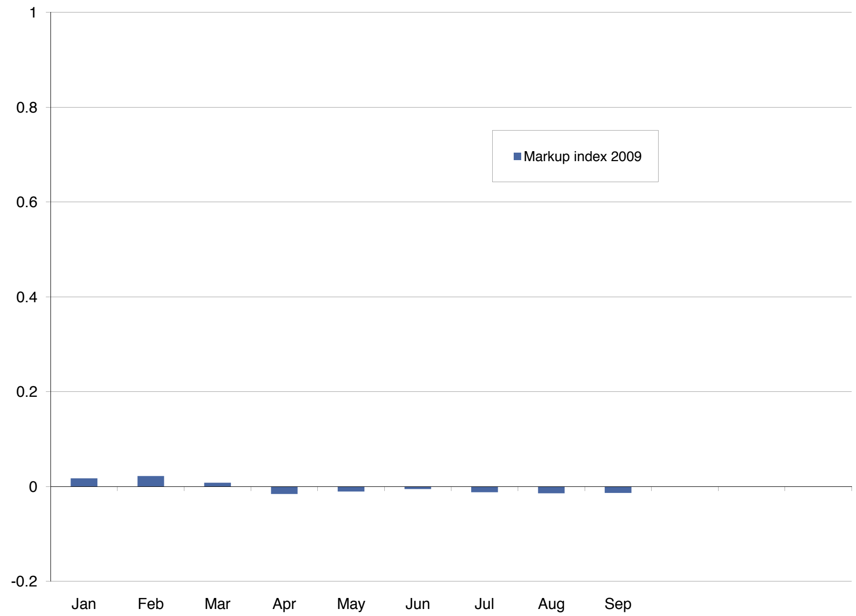

Table 2-40 Average, day-ahead marginal unit markup index (By price category): January through September 2009 (See 2007 SOM, Table 2-34)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.04)	($2.54)
$25 to $50	0.04	$0.40
$50 to $75	0.09	$5.26
$75 to $100	0.09	$7.98
$100 to $125	0.31	$33.95
$125 to $150	(0.04)	($8.16)
> $150	0.00	$0.00

Table 2-41 The markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September 2009 (New Table)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.52)	103.5%
Gas	CC	($0.03)	6.9%
Gas	CT	$0.01	(1.9%)
Gas	Diesel	$0.00	(0.0%)
Gas	Steam	$0.01	(1.4%)
Municipal Waste	Steam	($0.00)	0.2%
Oil	Diesel	($0.00)	0.0%
Oil	Steam	$0.02	(3.9%)
Wind	Wind	$0.02	(3.2%)
Total		($0.50)	100.0%

Table 2-42 Monthly markup components of day-ahead, load-weighted LMP: January through September 2009 (See 2007 SOM, Table 2-35)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$0.89	$1.62	$0.20
Feb	$0.76	$2.18	($0.75)
Mar	$0.16	$0.91	($0.65)
Apr	($0.97)	($0.33)	($1.72)
May	($0.62)	$0.07	($1.28)
Jun	($0.83)	$0.39	($2.37)
Jul	($1.10)	($0.55)	($1.80)
Aug	($1.63)	($0.75)	($2.57)
Sep	($1.31)	($0.69)	($2.00)
2009 (Jan - Sep)	($0.50)	$0.31	($1.39)

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Table 2-43 Day-ahead, average, zonal markup component: January through September 2009 (See 2007 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.04)	$0.78	($0.96)
AEP	($1.22)	($0.17)	($2.35)
AP	$0.40	$1.21	($0.48)
BGE	($0.22)	$0.60	($1.12)
ComEd	($0.71)	$0.02	($1.48)
DAY	($1.38)	($0.33)	($2.56)
DLCO	($1.17)	($0.22)	($2.21)
Dominion	($0.68)	$0.01	($1.41)
DPL	($0.10)	$0.60	($0.85)
JCPL	$0.00	$0.82	($0.95)
Met-Ed	$0.01	$0.74	($0.82)
PECO	($0.05)	$0.76	($0.95)
PENELEC	($0.09)	$0.65	($0.95)
Pepco	($0.51)	$0.18	($1.31)
PPL	$0.01	$0.77	($0.83)
PSEG	($0.12)	$0.62	($0.97)
RECO	($0.09)	$0.65	($1.02)

Table 2-44 Average, day-ahead markup (By price category): January through September 2009 (See 2007 SOM, Table 2-37)

	Average Markup Component	Frequency
Below $20	($1.63)	5%
$20 to $40	($1.68)	62%
$40 to $60	$1.01	26%
$60 to $80	$2.00	5%
$80 to $100	$2.70	2%
$100 to $120	$4.26	0%
$120 to $140	$1.43	0%
Above $160	$0.00	0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-45 Frequently mitigated units and associated units (By month): January through September 2009 (See 2008 SOM, Table 2-42)

	FMUs and AUs			Total Eligible for Any Adder
	Tier 1	Tier 2	Tier 3	
January	26	56	55	137
February	46	46	36	128
March	31	48	54	133
April	33	41	63	137
May	32	43	61	136
June	40	42	62	144
July	27	32	75	134
August	27	37	64	128
September	40	23	56	119

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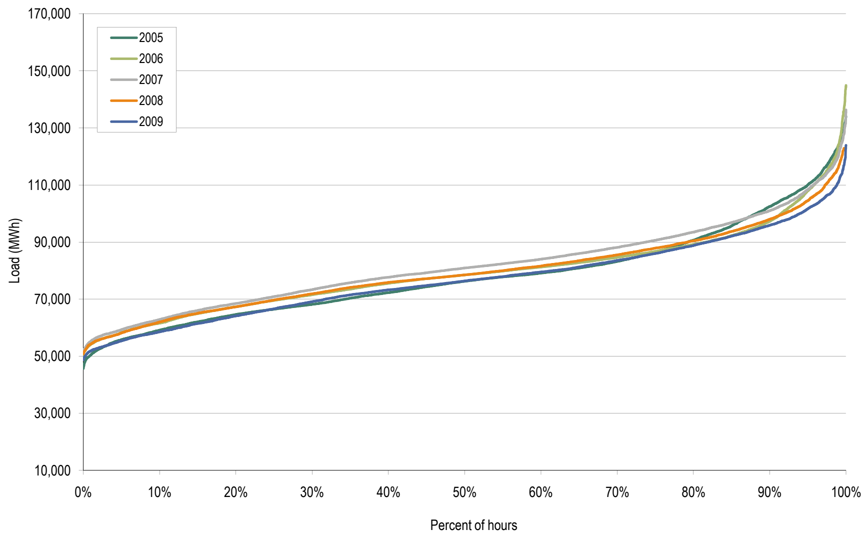
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

Figure 2-5 PJM real-time load duration curves: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-4)



PJM Real-Time, Annual Average Load

Table 2-46 PJM real-time average load: Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-44)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	30,113	30,170	5,529	NA	NA	NA
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	76,956	76,355	13,879	(3.2%)	(2.7%)	0.9%

PJM Real-Time, Monthly Average Load

Figure 2-6 PJM real-time average load: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-5)

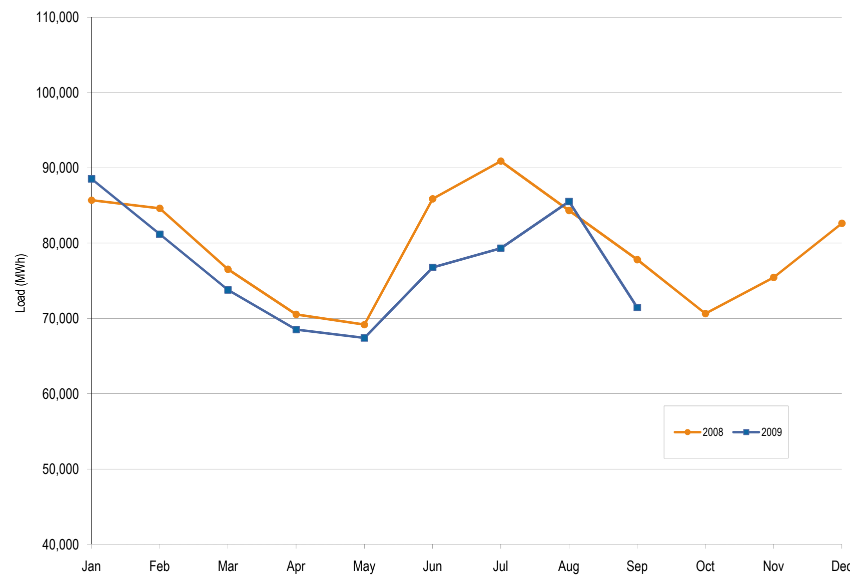


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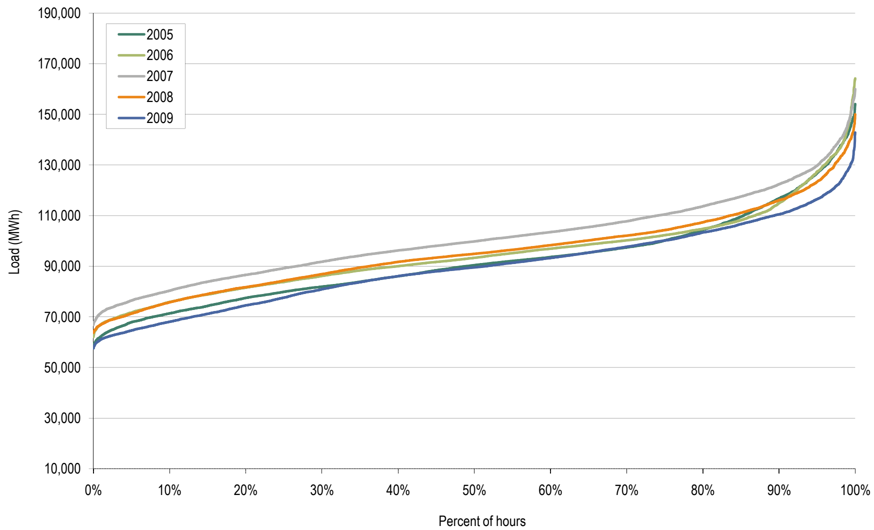
Table 2-47 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2008 and 2009 (See 2008 SOM, Table 2-45)

	2008			2009			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	54.94	70.16	81.30	52.48	67.85	77.91	(4.5%)	(3.3%)	(4.2%)
Jul	62.02	72.23	80.34	58.65	69.52	78.11	(5.4%)	(3.8%)	(2.8%)
Aug	59.82	69.67	78.55	57.45	71.63	81.01	(4.0%)	2.8%	3.1%

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-7 PJM day-ahead load duration curves: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-6)



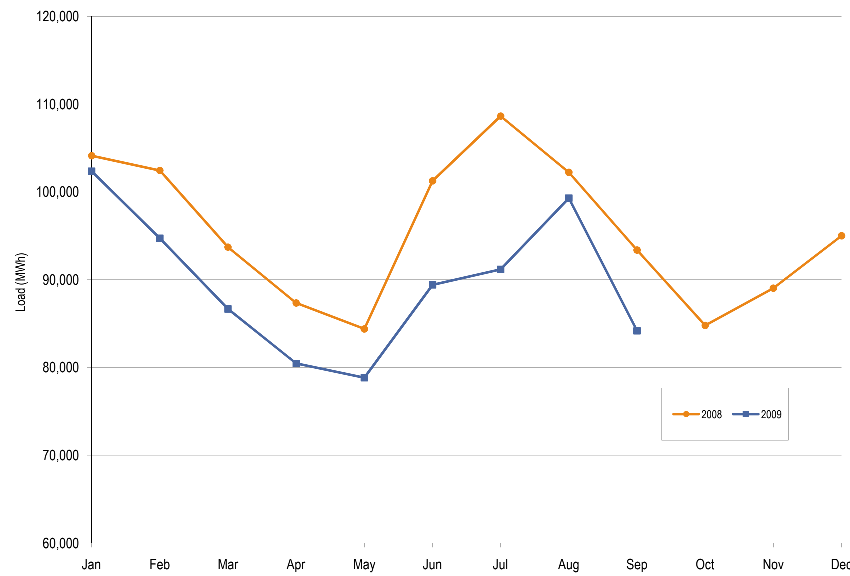
PJM Day-Ahead, Annual Average Load

Table 2-48 PJM day-ahead average load: Calendar years 2005 through September 2009 (See 2008 SOM, Table 2-46)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2005	92,002	90,424	17,381	NA	NA	NA
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	89,680	89,515	15,756	(6.1%)	(5.7%)	2.1%

PJM Day-Ahead, Monthly Average Load

Figure 2-8 PJM day-ahead average load: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-7)

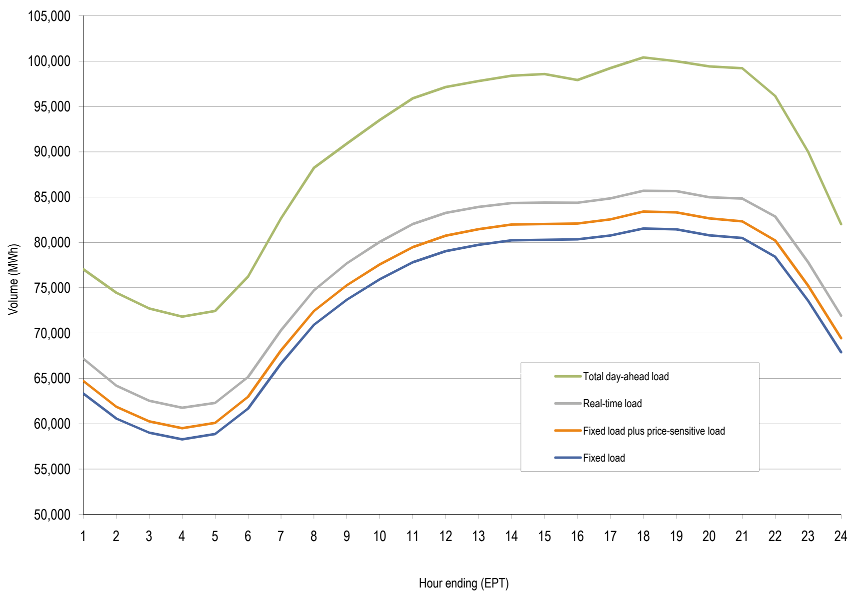


Real-Time and Day-Ahead Load

Table 2-49 Cleared day-ahead and real-time load (MWh): January through September 2009 (See 2008 SOM, Table 2-47)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus DEC Bid
Average	72,973	1,603	15,104	89,680	76,956	12,724	(2,380)
Median	72,358	1,609	15,369	89,515	76,355	13,160	(2,209)
Standard deviation	13,129	458	2,660	15,756	13,879	1,877	(783)

Figure 2-9 Day-ahead and real-time loads (Average hourly volumes): January through September 2009 (See 2008 SOM, Figure 2-8)

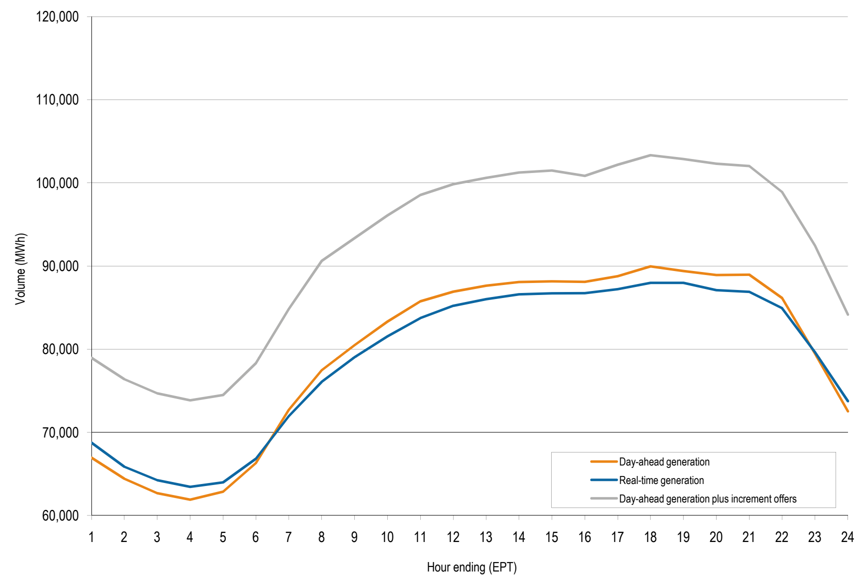


Real-Time and Day-Ahead Generation

Table 2-50 Day-ahead and real-time generation (MWh): January through September 2009 (See 2008 SOM, Table 2-48)

	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	79,502	12,684	92,186	78,850	652	13,336
Median	79,455	12,553	92,109	78,316	1,139	13,793
Standard deviation	15,458	1,615	16,220	14,242	1,216	1,978

Figure 2-10 Day-ahead and real-time generation (Average hourly volumes): January through September 2009 (See 2008 SOM, Figure 2-9)



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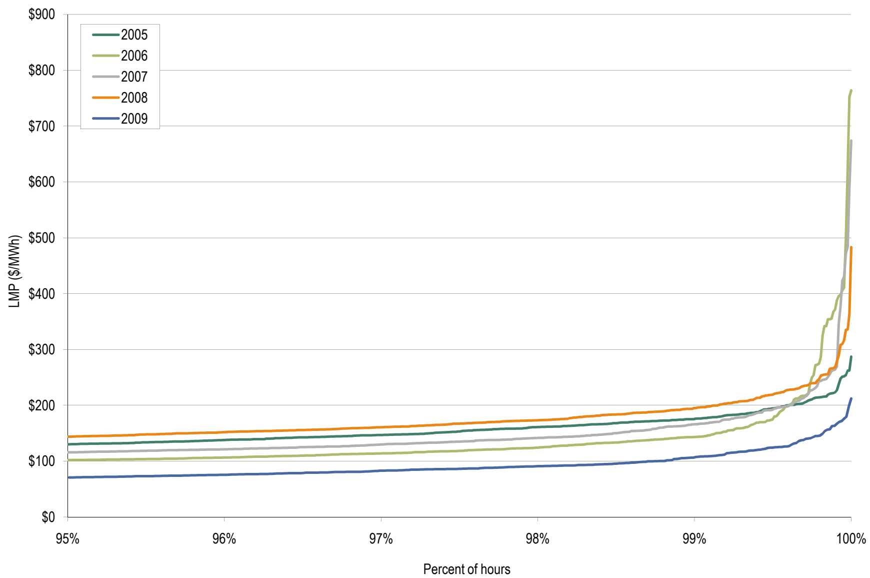
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-11 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-10)



PJM Real-Time, Annual Average LMP

Table 2-51 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-49)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$28.14	$19.11	$25.69	NA	NA	NA
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	$37.42	$33.00	$17.92	(43.6%)	(40.6%)	(53.6%)

Zonal Real-Time, Annual Average LMP

Table 2-52 Zonal real-time, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-50)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AECO	$88.73	$41.33	($47.40)	(53.4%)
AEP	$56.49	$33.81	($22.68)	(40.2%)
AP	$70.91	$38.89	($32.02)	(45.2%)
BGE	$87.55	$42.04	($45.51)	(52.0%)
ComEd	$53.10	$28.78	($24.32)	(45.8%)
DAY	$56.89	$33.56	($23.33)	(41.0%)
DLCO	$52.23	$32.47	($19.76)	(37.8%)
Dominion	$83.17	$40.55	($42.62)	(51.2%)
DPL	$84.20	$42.02	($42.18)	(50.1%)
JCPL	$86.31	$41.39	($44.92)	(52.0%)
Met-Ed	$81.33	$40.40	($40.94)	(50.3%)
PECO	$81.47	$40.51	($40.96)	(50.3%)
PENELEC	$67.83	$37.13	($30.70)	(45.3%)
Pepco	$87.88	$42.26	($45.62)	(51.9%)
PPL	$79.70	$39.87	($39.82)	(50.0%)
PSEG	$86.38	$41.88	($44.50)	(51.5%)
RECO	$84.50	$40.85	($43.65)	(51.7%)

Real-Time, Annual Average LMP by Jurisdiction

Table 2-53 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-51)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
Delaware	$83.06	$41.56	($41.50)	(50.0%)
Illinois	$53.10	$28.78	($24.32)	(45.8%)
Indiana	$56.19	$33.26	($22.93)	(40.8%)
Kentucky	$56.91	$33.63	($23.29)	(40.9%)
Maryland	$87.25	$42.03	($45.22)	(51.8%)
Michigan	$57.27	$34.48	($22.80)	(39.8%)
New Jersey	$86.71	$41.65	($45.05)	(52.0%)
North Carolina	$78.14	$39.56	($38.57)	(49.4%)
Ohio	$55.66	$33.33	($22.33)	(40.1%)
Pennsylvania	$74.55	$38.86	($35.69)	(47.9%)
Tennessee	$57.72	$33.69	($24.03)	(41.6%)
Virginia	$80.02	$39.83	($40.19)	(50.2%)
West Virginia	$58.18	$35.00	($23.18)	(39.8%)
District of Columbia	$87.91	$43.74	($44.17)	(50.2%)

Hub Real-Time, Annual Average LMP

Table 2-54 Hub real-time, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-52)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AEP Gen Hub	$53.11	$31.90	($21.22)	(39.9%)
AEP-DAY Hub	$56.14	$33.39	($22.75)	(40.5%)
Chicago Gen Hub	$52.24	$27.98	($24.25)	(46.4%)
Chicago Hub	$53.17	$28.98	($24.19)	(45.5%)
Dominion Hub	$80.83	$39.88	($40.95)	(50.7%)
Eastern Hub	$84.10	$41.97	($42.13)	(50.1%)
N Illinois Hub	$52.68	$28.60	($24.08)	(45.7%)
New Jersey Hub	$86.40	$41.61	($44.79)	(51.8%)
Ohio Hub	$56.24	$33.39	($22.84)	(40.6%)
West Interface Hub	$62.82	$34.73	($28.09)	(44.7%)
Western Hub	$73.86	$38.64	($35.23)	(47.7%)

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Real-Time, Load-Weighted, Average LMP

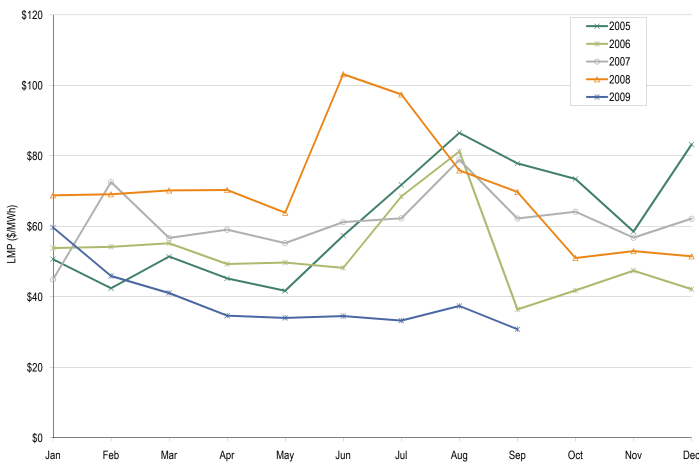
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-55 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-53)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$30.72	$20.51	$28.38	NA	NA	NA
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	$39.57	$34.57	$19.04	(44.4%)	(41.9%)	(53.5%)

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

Figure 2-12 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-11)



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

Table 2-56 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-54)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AECO	$99.86	$43.27	($56.59)	(56.7%)
AEP	$60.18	$35.56	($24.62)	(40.9%)
AP	$75.57	$41.49	($34.07)	(45.1%)
BGE	$95.51	$44.83	($50.68)	(53.1%)
ComEd	$57.78	$30.60	($27.19)	(47.0%)
DAY	$61.59	$35.30	($26.28)	(42.7%)
DLCO	$56.30	$33.65	($22.65)	(40.2%)
Dominion	$91.15	$43.46	($47.69)	(52.3%)
DPL	$91.73	$45.13	($46.59)	(50.8%)
JCPL	$94.68	$43.78	($50.90)	(53.8%)
Met-Ed	$87.05	$43.01	($44.03)	(50.6%)
PECO	$87.85	$42.69	($45.15)	(51.4%)
PENELEC	$71.33	$39.03	($32.30)	(45.3%)
Pepco	$96.23	$45.10	($51.13)	(53.1%)
PPL	$84.84	$42.83	($42.01)	(49.5%)
PSEG	$93.34	$43.74	($49.60)	(53.1%)
RECO	$92.92	$42.91	($50.01)	(53.8%)

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

Table 2-57 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-55)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
Delaware	$89.73	$44.21	($45.52)	(50.7%)
Illinois	$57.78	$30.60	($27.19)	(47.0%)
Indiana	$59.40	$34.42	($24.99)	(42.1%)
Kentucky	$61.40	$36.18	($25.22)	(41.1%)
Maryland	$95.61	$45.12	($50.49)	(52.8%)
Michigan	$61.71	$35.78	($25.93)	(42.0%)
New Jersey	$94.62	$43.67	($50.95)	(53.8%)
North Carolina	$87.14	$42.10	($45.04)	(51.7%)
Ohio	$59.49	$34.92	($24.58)	(41.3%)
Pennsylvania	$79.41	$41.12	($38.30)	(48.2%)
Tennessee	$60.38	$35.88	($24.50)	(40.6%)
Virginia	$87.45	$42.78	($44.67)	(51.1%)
West Virginia	$61.65	$37.21	($24.44)	(39.6%)
District of Columbia	$94.44	$46.29	($48.15)	(51.0%)

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

Fuel Cost

Table 2-58 PJM real-time, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through September 2009, year-over-year method (See 2008 SOM, Table 2-56)

	2008 (Jan - Sep) Load-Weighted LMP	2009 (Jan - Sep) Fuel-Cost-Adjusted, Load-Weighed LMP	Change
Average	$77.27	$68.61	(11.2%)

Figure 2-13 Spot average fuel price comparison: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-12)

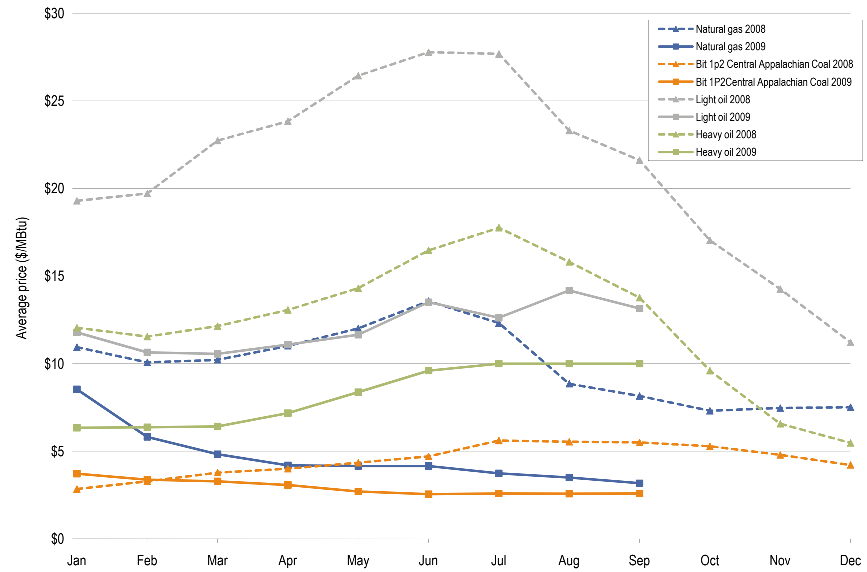
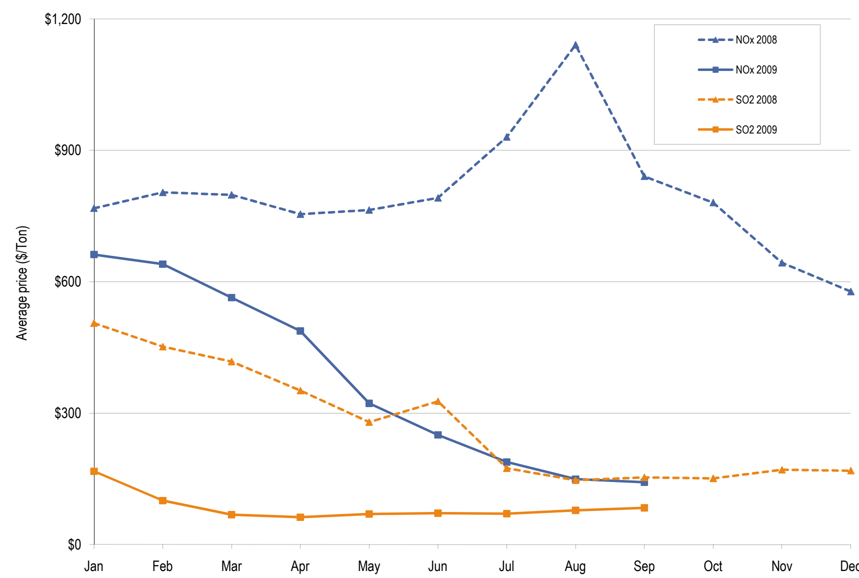


Figure 2-14 Spot average emission price comparison: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-13)



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Components of Real-Time, Load-Weighted LMP

Table 2-59 Components of PJM annual, load-weighted, average LMP: January through September 2009 (See 2008 SOM, Table 2-57)

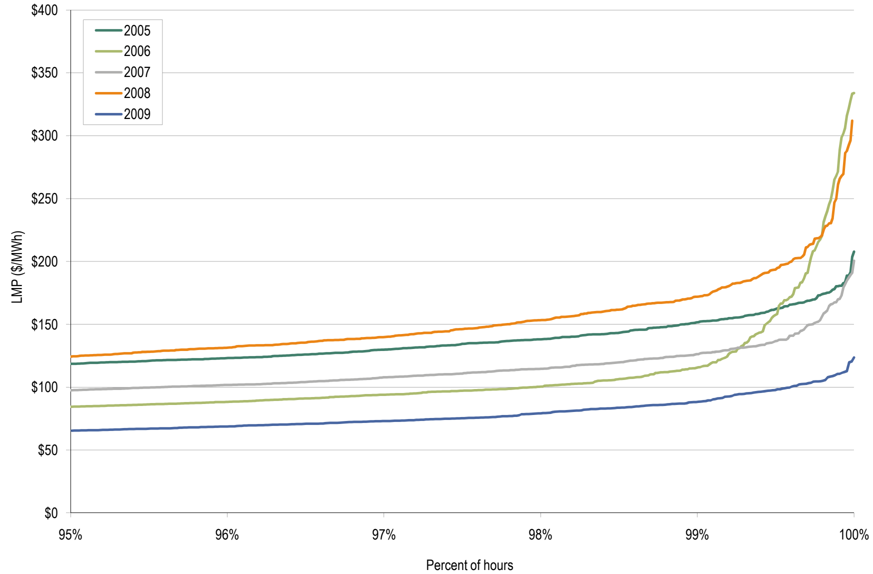
Element	Contribution to LMP	Percent
Coal	$22.06	55.8%
Gas	$12.10	30.6%
Oil	$3.26	8.2%
Uranium	$0.00	0.0%
Municipal Waste	$0.02	0.0%
FMU Adder	$0.19	0.5%
SO2	$1.33	3.4%
NOX	$0.49	1.2%
VOM	$4.40	11.1%
Markup	($3.67)	(9.3%)
Offline CT Adder	$0.05	0.1%
UDS Override Differential	($0.38)	(1.0%)
Dispatch Differential	($0.21)	(0.5%)
M2M Adder	($0.18)	(0.5%)
Flow violation Adjustment	($0.01)	(0.0%)
Unit LMP Differential	($0.00)	(0.0%)
NA	$0.12	0.3%
LMP	$39.57	100.0%

Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-15 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-14)



PJM Day-Ahead, Annual Average LMP

Table 2-60 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2005 through September 2009 (See 2008 SOM, Table 2-61)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2005	$57.89	$50.08	$30.04	NA	NA	NA
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	$37.35	$35.29	$14.32	(43.5%)	(40.1%)	(53.6%)

Zonal Day-Ahead, Annual Average LMP

Table 2-61 Zonal day-ahead, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-62)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AECO	$85.95	$42.15	($43.80)	(51.0%)
AEP	$56.89	$33.70	($23.19)	(40.8%)
AP	$70.23	$38.37	($31.86)	(45.4%)
BGE	$87.81	$42.75	($45.06)	(51.3%)
ComEd	$54.22	$28.80	($25.42)	(46.9%)
DAY	$56.96	$33.07	($23.90)	(42.0%)
DLCO	$54.88	$32.25	($22.63)	(41.2%)
Dominion	$82.35	$41.07	($41.28)	(50.1%)
DPL	$84.64	$42.43	($42.21)	(49.9%)
JCPL	$86.90	$41.99	($44.90)	(51.7%)
Met-Ed	$81.95	$40.87	($41.08)	(50.1%)
PECO	$82.47	$41.37	($41.09)	(49.8%)
PENELEC	$70.04	$37.46	($32.58)	(46.5%)
Pepco	$88.50	$42.91	($45.59)	(51.5%)
PPL	$80.45	$40.45	($40.00)	(49.7%)
PSEG	$86.72	$42.56	($44.16)	(50.9%)
RECO	$84.94	$41.51	($43.44)	(51.1%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-62 Day-ahead, simple average LMP (Dollars per MWh) by jurisdiction: January through September 2008 and 2009 (See 2008 SOM, Table 2-63)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
Delaware	$83.38	$41.81	($41.57)	(49.9%)
Illinois	$54.22	$28.80	($25.42)	(46.9%)
Indiana	$57.10	$33.14	($23.95)	(41.9%)
Kentucky	$56.47	$33.41	($23.05)	(40.8%)
Maryland	$87.12	$42.64	($44.48)	(51.1%)
Michigan	$58.00	$34.41	($23.59)	(40.7%)
New Jersey	$86.71	$42.33	($44.38)	(51.2%)
North Carolina	$77.70	$40.03	($37.68)	(48.5%)
Ohio	$56.21	$33.00	($23.21)	(41.3%)
Pennsylvania	$75.69	$39.29	($36.40)	(48.1%)
Tennessee	$57.49	$33.90	($23.59)	(41.0%)
Virginia	$79.32	$40.37	($38.95)	(49.1%)
West Virginia	$57.98	$34.79	($23.19)	(40.0%)
District of Columbia	$88.21	$44.06	($44.15)	(50.1%)

Day-Ahead, Load-Weighted, Average LMP

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

Table 2-63 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2005 through September 2009 (See 2008 SOM, Table 2-64)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2005	$62.50	$54.74	$31.72	NA	NA	NA
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	$39.35	$36.92	$14.98	(44.0%)	(41.3%)	(54.8%)

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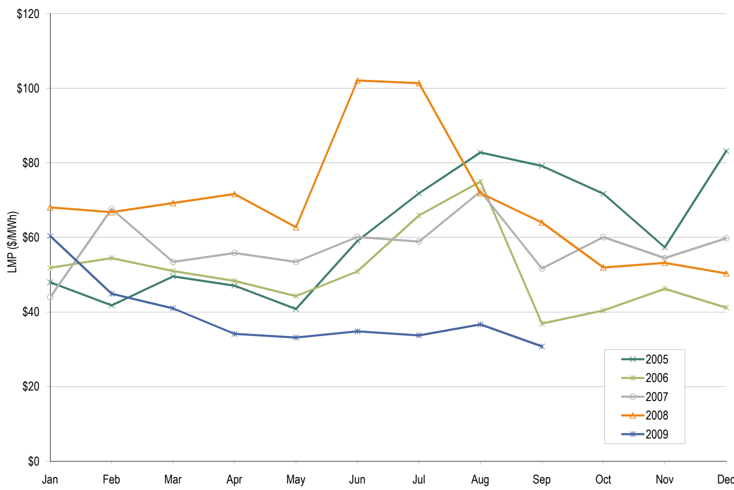
PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 2-16 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-15)



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-64 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-65)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
AECO	$96.75	$44.48	($52.27)	(54.0%)
AEP	$60.23	$35.37	($24.86)	(41.3%)
AP	$73.22	$40.77	($32.45)	(44.3%)
BGE	$95.41	$45.38	($50.03)	(52.4%)
ComEd	$57.63	$30.11	($27.52)	(47.8%)
DAY	$60.93	$34.63	($26.31)	(43.2%)
DLCO	$58.72	$33.33	($25.39)	(43.2%)
Dominion	$89.53	$43.87	($45.66)	(51.0%)
DPL	$91.81	$45.11	($46.69)	(50.9%)
JCPL	$94.43	$44.22	($50.21)	(53.2%)
Met-Ed	$86.79	$43.54	($43.25)	(49.8%)
PECO	$88.34	$43.49	($44.85)	(50.8%)
PENELEC	$72.64	$39.06	($33.57)	(46.2%)
Pepco	$94.03	$45.43	($48.60)	(51.7%)
PPL	$84.92	$43.14	($41.79)	(49.2%)
PSEG	$93.15	$44.48	($48.67)	(52.2%)
RECO	$92.61	$43.93	($48.68)	(52.6%)

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

Table 2-65 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-66)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Difference	Difference as Percent of 2008
Delaware	$90.25	$44.31	($45.94)	(50.9%)
Illinois	$57.63	$30.11	($27.52)	(47.8%)
Indiana	$60.44	$34.23	($26.21)	(43.4%)
Kentucky	$59.67	$35.77	($23.89)	(40.0%)
Maryland	$93.78	$45.41	($48.37)	(51.6%)
Michigan	$61.53	$35.58	($25.95)	(42.2%)
New Jersey	$93.93	$44.38	($49.55)	(52.8%)
North Carolina	$85.12	$42.71	($42.41)	(49.8%)
Ohio	$59.62	$34.56	($25.06)	(42.0%)
Pennsylvania	$79.64	$41.36	($38.28)	(48.1%)
Tennessee	$60.41	$35.96	($24.46)	(40.5%)
Virginia	$85.70	$43.12	($42.58)	(49.7%)
West Virginia	$61.14	$36.71	($24.43)	(40.0%)
District of Columbia	$93.03	$46.86	($46.17)	(49.6%)

Components of Day-Ahead, Load-Weighted LMP

Table 2-66 Components of PJM day-ahead, annual, load-weighted, average LMP: January through September 2009 (See 2008 SOM, Table 2-57)

Element	Contribution to LMP	Percent
DEC	$12.40	31.5%
INC	$11.63	29.6%
Coal	$9.15	23.3%
Gas	$2.41	6.1%
Price sensitive demand	$1.37	3.5%
VOM	$0.90	2.3%
Transaction	$0.87	2.2%
Oil	$0.74	1.9%
SO2	$0.29	0.7%
NOx	$0.10	0.2%
Misc	$0.00	0.0%
Constrained off	$0.00	0.0%
FMU adder	$0.00	0.0%
NA	($0.00)	(0.0%)
Markup	($0.50)	(1.3%)
LMP	$39.35	100.0%

Marginal Losses

Table 2-67 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through September 2009 (See 2008 SOM, Table 2-67)

	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	$66.29	$0.06	$0.04
2009	$37.42	$37.35	$0.05	$0.03

Table 2-68 Zonal real-time, simple average LMP components (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-68)

	2008 (Jan - Sep)				2009 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$88.73	$71.83	$12.91	$3.99	$41.33	$37.35	$2.13	$1.85
AEP	$56.49	$71.83	($12.66)	($2.68)	$33.81	$37.35	($2.32)	($1.23)
AP	$70.91	$71.83	($0.04)	($0.88)	$38.89	$37.35	$1.62	($0.08)
BGE	$87.55	$71.83	$12.82	$2.90	$42.04	$37.35	$3.05	$1.65
ComEd	$53.10	$71.83	($15.07)	($3.66)	$28.78	$37.35	($6.24)	($2.33)
DAY	$56.89	$71.83	($13.36)	($1.57)	$33.56	$37.35	($2.99)	($0.80)
DLCO	$52.23	$71.83	($16.33)	($3.27)	$32.47	$37.35	($3.53)	($1.35)
Dominion	$83.17	$71.83	$10.47	$0.87	$40.55	$37.35	$2.60	$0.60
DPL	$84.20	$71.83	$8.88	$3.50	$42.02	$37.35	$2.67	$2.00
JCPL	$86.31	$71.83	$10.32	$4.17	$41.39	$37.35	$2.11	$1.93
Met-Ed	$81.33	$71.83	$7.44	$2.06	$40.40	$37.35	$2.21	$0.83
PECO	$81.47	$71.83	$6.78	$2.86	$40.51	$37.35	$1.88	$1.28
PENELEC	$67.83	$71.83	($3.27)	($0.72)	$37.13	$37.35	($0.04)	($0.17)
Pepco	$87.88	$71.83	$14.16	$1.89	$42.26	$37.35	$3.82	$1.09
PPL	$79.70	$71.83	$6.20	$1.67	$39.87	$37.35	$1.90	$0.63
PSEG	$86.38	$71.83	$10.35	$4.20	$41.88	$37.35	$2.53	$2.01
RECO	$84.50	$71.83	$8.90	$3.77	$40.85	$37.35	$1.73	$1.77

Table 2-69 Hub real-time, simple average LMP components (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-69)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$31.90	$37.35	($3.08)	($2.37)
AEP-DAY Hub	$33.39	$37.35	($2.57)	($1.38)
Chicago Gen Hub	$27.98	$37.35	($6.55)	($2.82)
Chicago Hub	$28.98	$37.35	($6.06)	($2.31)
Dominion Hub	$39.88	$37.35	$2.29	$0.24
Eastern Hub	$41.97	$37.35	$2.45	$2.17
N Illinois Hub	$28.60	$37.35	($6.24)	($2.51)
New Jersey Hub	$41.61	$37.35	$2.33	$1.93
Ohio Hub	$33.39	$37.35	($2.61)	($1.35)
West Interface Hub	$34.73	$37.35	($1.40)	($1.23)
Western Hub	$38.64	$37.35	$1.46	($0.18)

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

Table 2-70 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-70)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$43.27	$38.98	$2.29	$1.99
AEP	$35.56	$39.65	($2.77)	($1.32)
AP	$41.49	$39.85	$1.76	($0.11)
BGE	$44.83	$39.58	$3.48	$1.77
ComEd	$30.60	$39.06	($6.09)	($2.38)
DAY	$35.30	$39.57	($3.47)	($0.81)
DLCO	$33.65	$39.05	($3.96)	($1.44)
Dominion	$43.46	$39.77	$3.04	$0.64
DPL	$45.13	$39.79	$3.14	$2.20
JCPL	$43.78	$39.46	$2.25	$2.07
Met-Ed	$43.01	$39.61	$2.49	$0.91
PECO	$42.69	$39.26	$2.06	$1.37
PENELEC	$39.03	$39.41	($0.18)	($0.20)
Pepco	$45.10	$39.43	$4.52	$1.15
PPL	$42.83	$39.89	$2.22	$0.72
PSEG	$43.74	$38.97	$2.66	$2.11
RECO	$42.91	$39.23	$1.81	$1.88
PJM	$39.57	$39.49	$0.04	$0.03

Table 2-71 PJM day-ahead, simple average LMP components (Dollars per MWh): 2006 through September 2009 (See 2008 SOM, Table 2-71)

	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	$37.35	$37.52	($0.07)	($0.10)

Table 2-72 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through September 2008 and 2009. (See 2008 SOM, Table 2-72)

	2008 (Jan - Sep)				2009 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$85.95	$71.78	$9.05	$5.12	$42.15	$37.52	$2.35	$2.29
AEP	$56.89	$71.78	($11.24)	($3.65)	$33.70	$37.52	($2.24)	($1.58)
AP	$70.23	$71.78	($0.47)	($1.08)	$38.37	$37.52	$0.83	$0.03
BGE	$87.81	$71.78	$12.50	$3.52	$42.75	$37.52	$3.24	$2.00
ComEd	$54.22	$71.78	($12.82)	($4.74)	$28.80	$37.52	($5.61)	($3.11)
DAY	$56.96	$71.78	($11.68)	($3.14)	$33.07	$37.52	($3.01)	($1.44)
DLCO	$54.88	$71.78	($12.84)	($4.06)	$32.25	$37.52	($3.73)	($1.54)
Dominion	$82.35	$71.78	$9.51	$1.07	$41.07	$37.52	$2.59	$0.97
DPL	$84.64	$71.78	$8.60	$4.27	$42.43	$37.52	$2.58	$2.33
JCPL	$86.90	$71.78	$9.18	$5.93	$41.99	$37.52	$2.07	$2.41
Met-Ed	$81.95	$71.78	$7.39	$2.78	$40.87	$37.52	$2.33	$1.03
PECO	$82.47	$71.78	$6.46	$4.23	$41.37	$37.52	$2.10	$1.76
PENELEC	$70.04	$71.78	($1.22)	($0.52)	$37.46	$37.52	$0.01	($0.06)
Pepco	$88.50	$71.78	$14.06	$2.66	$42.91	$37.52	$3.78	$1.61
PPL	$80.45	$71.78	$6.23	$2.45	$40.45	$37.52	$2.12	$0.81
PSEG	$86.72	$71.78	$8.84	$6.10	$42.56	$37.52	$2.45	$2.59
RECO	$84.94	$71.78	$7.62	$5.55	$41.51	$37.52	$1.69	$2.30

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

Table 2-73 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-73)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$44.48	$39.38	$2.63	$2.47
AEP	$35.37	$39.80	($2.72)	($1.71)
AP	$40.77	$40.03	$0.72	$0.01
BGE	$45.38	$39.57	$3.66	$2.15
ComEd	$30.11	$38.88	($5.58)	($3.20)
DAY	$34.63	$39.66	($3.51)	($1.52)
DLCO	$33.33	$39.06	($4.10)	($1.64)
Dominion	$43.87	$39.81	$3.02	$1.05
DPL	$45.11	$39.66	$2.95	$2.51
JCPL	$44.22	$39.44	$2.23	$2.55
Met-Ed	$43.54	$39.75	$2.67	$1.12
PECO	$43.49	$39.32	$2.30	$1.87
PENELEC	$39.06	$39.22	($0.10)	($0.06)
Pepco	$45.43	$39.30	$4.40	$1.73
PPL	$43.14	$39.78	$2.44	$0.92
PSEG	$44.48	$39.19	$2.59	$2.71
RECO	$43.93	$39.67	$1.80	$2.45
PJM	$39.35	$39.50	($0.05)	($0.10)

Monthly Marginal Loss Costs

Table 2-74 Marginal loss costs by type (Dollars (Millions)): January through September 2009 (See 2008 SOM, Table 2-74)

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$52.4	($143.8)	$14.2	$210.5	$1.0	($2.6)	($6.8)	($3.2)	$207.3
Feb	$35.9	($88.8)	$8.2	$132.9	($0.3)	($1.2)	($4.2)	($3.2)	$129.7
Mar	$34.9	($78.6)	$8.5	$122.0	($0.8)	($1.3)	($5.3)	($4.8)	$117.2
Apr	$22.2	($59.5)	$5.9	$87.6	($1.3)	($0.1)	($3.7)	($4.9)	$82.6
May	$20.3	($53.6)	$4.6	$78.5	($0.5)	($0.4)	($2.5)	($2.5)	$76.0
Jun	$18.6	($71.2)	$3.1	$92.9	($0.5)	($1.5)	($1.5)	($0.6)	$92.3
Jul	$22.8	($70.4)	$3.1	$96.3	($0.1)	($1.6)	($0.8)	$0.8	$97.0
Aug	$27.4	($87.0)	$3.3	$117.7	($0.1)	($0.9)	($1.2)	($0.3)	$117.4
Sep	$17.1	($55.6)	$2.2	$74.9	($1.0)	($0.5)	($1.2)	($1.7)	$73.2
Total	$251.6	($708.5)	$53.2	$1,013.2	($3.5)	($10.2)	($27.1)	($20.4)	$992.8

Zonal Marginal Loss Costs

Table 2-75 Marginal loss costs by control zone and type (Dollars (Millions)): January through September 2009 (See 2008 SOM, Table 2-75)

	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	$20.3	$3.9	$0.2	$16.6	$0.3	($0.1)	$0.1	$0.5	$17.2
AEP	($37.0)	($190.3)	$14.3	$167.6	$0.2	($0.2)	($1.2)	($0.8)	$166.8
AP	$1.8	($63.3)	$6.9	$71.9	$2.1	$3.2	($2.9)	($4.0)	$68.0
BGE	$42.4	$8.7	$0.7	$34.4	$2.1	($1.3)	($0.6)	$2.8	$37.3
ComEd	($115.7)	($314.3)	$0.2	$198.8	$0.0	($2.8)	$0.0	$2.8	$201.7
DAY	($3.3)	($42.0)	$1.0	$39.6	($0.2)	$1.7	$0.1	($1.8)	$37.9
DLCO	($16.5)	($33.7)	$0.1	$17.3	($1.9)	$0.1	($0.0)	($2.0)	$15.3
Dominion	$66.2	($33.8)	$3.0	$103.0	$1.5	($1.2)	($1.0)	$1.7	$104.7
DPL	$39.0	$6.4	$0.4	$33.0	($2.4)	($0.8)	($0.2)	($1.8)	$31.2
JCPL	$46.2	$16.9	$0.2	$29.5	$0.0	($1.7)	($0.1)	$1.6	$31.1
Met-Ed	$12.9	$1.2	$0.2	$12.0	($0.0)	($0.3)	($0.1)	$0.1	$12.1
PECO	$46.4	$8.2	$0.0	$38.3	($0.5)	($0.7)	($0.0)	$0.2	$38.4
PENELEC	($11.0)	($64.8)	$0.4	$54.2	($1.7)	$0.6	($0.1)	($2.4)	$51.7
PEPCO	$61.4	$26.7	$1.8	$36.4	($1.7)	($2.2)	($1.2)	($0.6)	$35.8
PJM	($4.3)	($31.0)	$18.4	$45.2	($0.6)	($8.4)	($16.2)	($8.3)	$36.8
PPL	$27.3	($19.3)	$1.1	$47.7	($0.3)	$0.7	$0.1	($0.8)	$46.9
PSEG	$72.7	$12.1	$4.3	$64.9	($0.6)	$3.4	($3.6)	($7.6)	$57.3
RECO	$2.7	$0.0	$0.1	$2.7	$0.0	($0.0)	($0.1)	($0.0)	$2.7
Total	$251.6	($708.5)	$53.2	$1,013.2	($3.5)	($10.2)	($27.1)	($20.4)	$992.8

Table 2-76 Monthly marginal loss costs by control zone (Dollars (Millions)): January through September 2009 (See 2008 SOM, Table 2-76)

	Marginal Loss Costs by Control Zone (Millions)									
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Grand Total
AECO	$3.4	$2.0	$1.7	$1.7	$1.2	$1.3	$2.0	$2.7	$1.2	$17.2
AEP	$32.6	$22.9	$18.6	$13.1	$11.7	$17.5	$15.0	$21.9	$13.4	$166.8
AP	$18.0	$9.4	$8.4	$6.2	$4.8	$5.4	$5.0	$7.5	$3.3	$68.0
BGE	$7.0	$4.4	$4.2	$2.6	$2.8	$3.4	$4.1	$5.2	$3.4	$37.3
ComEd	$36.3	$26.1	$28.0	$19.4	$16.9	$18.4	$19.3	$21.2	$16.1	$201.7
DAY	$7.8	$4.6	$4.5	$3.3	$2.2	$3.7	$3.9	$4.4	$3.5	$37.9
DLCO	$3.5	$1.9	$2.1	$1.2	$0.7	$1.6	$1.6	$1.4	$1.3	$15.3
Dominion	$20.2	$11.8	$11.1	$7.0	$8.2	$11.5	$12.2	$14.3	$8.2	$104.7
DPL	$6.8	$4.3	$4.0	$2.9	$2.4	$2.2	$3.0	$3.4	$2.1	$31.2
JCPL	$8.3	$5.6	$3.7	$2.4	$2.1	$1.8	$2.5	$3.3	$1.4	$31.1
Met-Ed	$2.4	$1.4	$1.2	$0.9	$0.8	$1.4	$1.4	$1.6	$1.1	$12.1
PECO	$8.0	$4.3	$3.5	$2.6	$2.9	$4.1	$4.1	$5.6	$3.4	$38.4
PENELEC	$12.1	$5.6	$4.3	$4.1	$5.0	$5.6	$5.9	$6.0	$3.2	$51.7
PEPCO	$6.0	$3.6	$4.3	$3.1	$2.8	$3.7	$4.1	$5.0	$3.2	$35.8
PJM	$14.1	$6.0	$4.8	$2.0	$3.2	$1.3	$2.6	$2.2	$0.8	$36.8
PPL	$10.1	$6.5	$5.5	$3.8	$3.0	$4.5	$4.9	$5.1	$3.6	$46.9
PSEG	$10.1	$8.8	$7.1	$6.0	$5.1	$4.9	$5.3	$6.1	$4.0	$57.3
RECO	$0.6	$0.4	$0.3	$0.3	$0.2	$0.2	$0.2	$0.3	$0.2	$2.7
Total	$207.3	$129.7	$117.2	$82.6	$76.0	$92.3	$97.0	$117.4	$73.2	$992.8

Virtual Offers and Bids

Table 2-77 Type of day-ahead marginal units: January through September 2009 (See 2008 SOM, Table 2-77)

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	20.6%	32.2%	33.3%	13.0%	1.0%
Feb	17.4%	38.8%	28.5%	14.6%	0.8%
Mar	14.9%	39.8%	27.6%	17.0%	0.7%
Apr	16.2%	38.7%	28.6%	16.0%	0.5%
May	12.2%	38.5%	29.1%	19.0%	1.2%
Jun	17.3%	30.7%	27.2%	24.0%	0.8%
Jul	12.4%	34.8%	31.2%	20.9%	0.7%
Aug	11.5%	29.4%	36.5%	22.2%	0.4%
Sep	12.8%	33.3%	25.7%	27.5%	0.6%
Annual	15.0%	35.1%	29.8%	19.4%	0.7%

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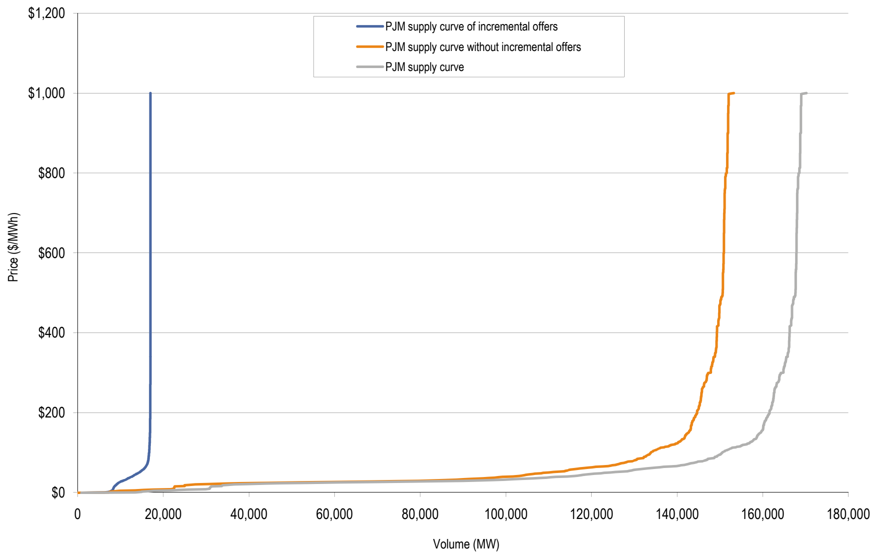
Figure 2-17 PJM day-ahead aggregate supply curves: 2009 example day (See 2008 SOM, Figure 2-16)



Price Convergence

Table 2-78 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-78)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$37.35	$37.42	$0.08	0.2%
Median	$35.29	$33.00	($2.29)	(7.0%)
Standard deviation	$14.32	$17.92	$3.60	20.1%

Table 2-79 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-79)

Year	Day Ahead	Real Time	Difference	Difference as Percent 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	$37.35	$37.42	$0.08	0.2%

Table 2-80 Frequency distribution by hours of PJM real-time and day-ahead LMP difference (Dollars per MWh): 2005 through September 2009 (See 2008 SOM, Table 2-80)

	2005		2006		2007		2008		2009	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	1	0.01%	1	0.02%	0	0.00%	1	0.01%	0	0.00%
($100) to ($50)	64	0.74%	9	0.13%	33	0.38%	88	1.01%	3	0.05%
($50) to $0	5,015	57.99%	5,205	59.54%	4,600	52.89%	5,120	59.30%	3,776	57.69%
$0 to $50	3,471	97.61%	3,372	98.04%	3,827	96.58%	3,247	96.27%	2,736	99.45%
$50 to $100	190	99.78%	152	99.77%	255	99.49%	284	99.50%	34	99.97%
$100 to $150	17	99.98%	9	99.87%	31	99.84%	37	99.92%	2	100.00%
$150 to $200	2	100.00%	4	99.92%	5	99.90%	4	99.97%	0	100.00%
$200 to $250	0	100.00%	1	99.93%	1	99.91%	2	99.99%	0	100.00%
$250 to $300	0	100.00%	3	99.97%	3	99.94%	0	99.99%	0	100.00%
$300 to $350	0	100.00%	0	99.97%	2	99.97%	1	100.00%	0	100.00%
$350 to $400	0	100.00%	1	99.98%	1	99.98%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	99.98%	1	99.99%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	1	99.99%	1	100.00%	0	100.00%	0	100.00%
>= $500	0	100.00%	1	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-18 Hourly real-time minus hourly day-ahead LMP: January through September 2009 (See 2008 SOM, Figure 2-17)

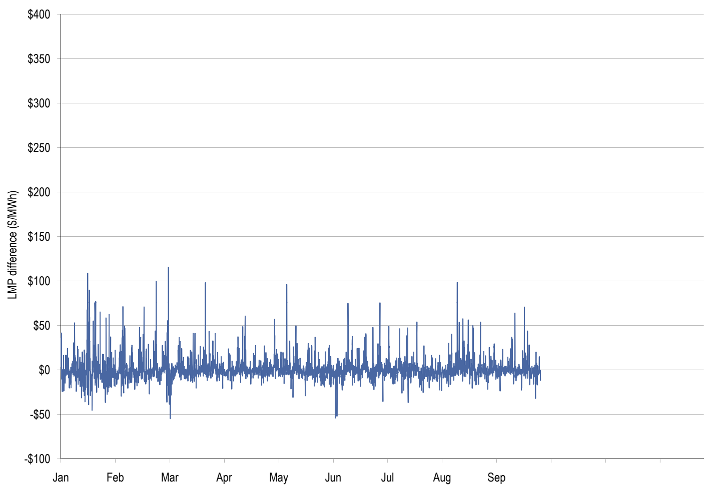


Figure 2-19 Monthly average of real-time minus day-ahead LMP: January through September 2009 (See 2008 SOM, Figure 2-18)

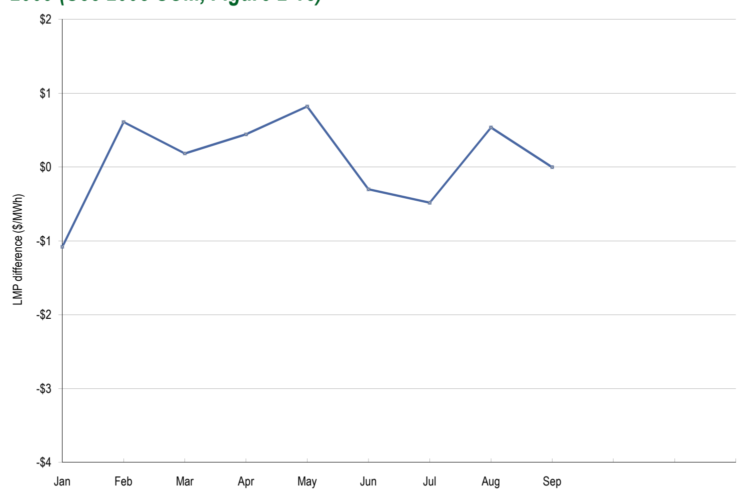


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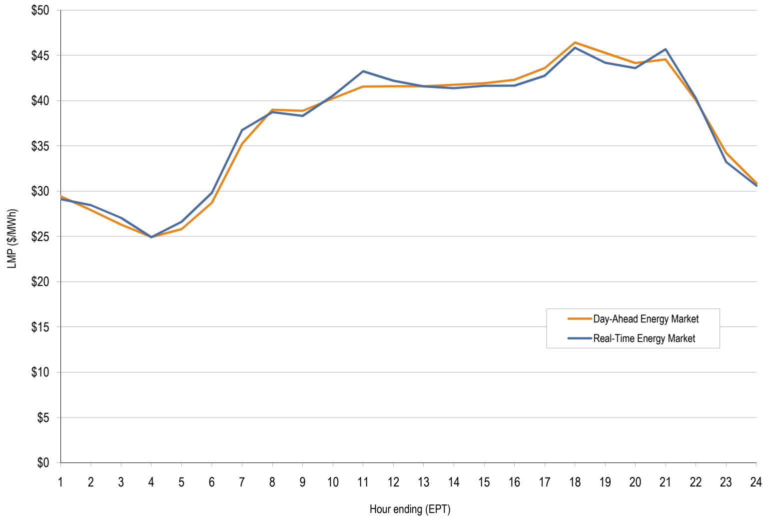
Figure 2-20 PJM system hourly average LMP: January through September 2009 (See 2008 SOM, Figure 2-19)



Zonal Price Convergence

Table 2-81 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-81)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$42.15	$41.33	($0.82)	(2.0%)
AEP	$33.70	$33.81	$0.11	0.3%
AP	$38.37	$38.89	$0.52	1.3%
BGE	$42.75	$42.04	($0.71)	(1.7%)
ComEd	$28.80	$28.78	($0.02)	(0.1%)
DAY	$33.07	$33.56	$0.49	1.5%
DLCO	$32.25	$32.47	$0.22	0.7%
Dominion	$41.07	$40.55	($0.52)	(1.3%)
DPL	$42.43	$42.02	($0.41)	(1.0%)
JCPL	$41.99	$41.39	($0.60)	(1.4%)
Met-Ed	$40.87	$40.40	($0.48)	(1.2%)
PECO	$41.37	$40.51	($0.86)	(2.1%)
PENELEC	$37.46	$37.13	($0.33)	(0.9%)
Pepco	$42.91	$42.26	($0.65)	(1.5%)
PPL	$40.45	$39.87	($0.58)	(1.5%)
PSEG	$42.56	$41.88	($0.67)	(1.6%)
RECO	$41.51	$40.85	($0.66)	(1.6%)

Price Convergence by Jurisdiction

Table 2-82 Jurisdiction Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-82)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$41.81	$41.56	($0.25)	(0.6%)
Illinois	$28.80	$28.78	($0.02)	(0.1%)
Indiana	$33.14	$33.26	$0.11	0.3%
Kentucky	$33.41	$33.63	$0.21	0.6%
Maryland	$42.64	$42.03	($0.61)	(1.5%)
Michigan	$34.41	$34.48	$0.06	0.2%
New Jersey	$42.33	$41.65	($0.67)	(1.6%)
North Carolina	$40.03	$39.56	($0.46)	(1.2%)
Ohio	$33.00	$33.33	$0.33	1.0%
Pennsylvania	$39.29	$38.86	($0.42)	(1.1%)
Tennessee	$33.90	$33.69	($0.22)	(0.6%)
Virginia	$40.37	$39.83	($0.54)	(1.3%)
West Virginia	$34.79	$35.00	$0.22	0.6%
District of Columbia	$44.06	$43.74	($0.32)	(0.7%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-83 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2008 through September 2009 (See 2008 SOM, Table 2-83)

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	14.3%	17.3%	68.4%	12.6%	15.4%	72.0%	(1.7%)	(1.9%)	3.6%
Feb	15.2%	17.3%	67.5%	13.4%	14.5%	72.1%	(1.7%)	(2.9%)	4.6%
Mar	16.0%	17.1%	66.9%	13.8%	16.7%	69.5%	(2.3%)	(0.4%)	2.6%
Apr	16.6%	18.0%	65.4%	13.5%	17.2%	69.3%	(3.1%)	(0.8%)	3.9%
May	16.0%	18.8%	65.3%	14.6%	18.8%	66.7%	(1.4%)	(0.0%)	1.4%
Jun	13.1%	21.0%	65.9%	12.5%	16.5%	71.0%	(0.6%)	(4.5%)	5.1%
Jul	13.7%	20.6%	65.7%	12.6%	16.9%	70.5%	(1.2%)	(3.7%)	4.8%
Aug	14.9%	22.6%	62.4%	11.7%	16.0%	72.3%	(3.2%)	(6.6%)	9.9%
Sep	14.7%	23.0%	62.2%	12.5%	18.1%	69.4%	(2.3%)	(4.9%)	7.2%
Oct	15.1%	22.7%	62.2%						
Nov	14.8%	22.9%	62.3%						
Dec	12.1%	20.5%	67.4%						
Annual	14.6%	20.1%	65.2%	13.0%	16.6%	70.4%	(1.7%)	(3.5%)	5.2%

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Day-Ahead Load and Spot Market

Table 2-84 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2008 through September 2009 (See 2008 SOM, Table 2-84)

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.2%	15.6%	80.2%	4.4%	13.9%	81.7%	0.2%	(1.7%)	1.5%
Feb	4.5%	16.0%	79.5%	4.5%	12.7%	82.9%	(0.1%)	(3.3%)	3.4%
Mar	4.7%	16.0%	79.3%	4.3%	13.2%	82.5%	(0.4%)	(2.8%)	3.2%
Apr	5.0%	16.8%	78.2%	4.4%	14.1%	81.5%	(0.5%)	(2.7%)	3.3%
May	5.0%	18.2%	76.8%	4.6%	15.9%	79.5%	(0.4%)	(2.3%)	2.7%
Jun	5.5%	20.2%	74.3%	4.7%	14.2%	81.2%	(0.8%)	(6.1%)	6.9%
Jul	5.6%	20.4%	74.0%	5.6%	16.3%	78.2%	(0.0%)	(4.2%)	4.2%
Aug	4.9%	20.2%	75.0%	5.1%	15.5%	79.3%	0.3%	(4.6%)	4.4%
Sep	5.4%	19.3%	75.3%	4.7%	16.3%	78.9%	(0.7%)	(2.9%)	3.6%
Oct	5.4%	20.3%	74.3%						
Nov	5.6%	18.9%	75.5%						
Dec	4.6%	19.1%	76.3%						
Annual	5.0%	18.4%	76.5%	4.7%	14.5%	80.8%	(0.3%)	(4.0%)	4.3%

Virtual Markets

Increment Offers and Decrement Bids

Table 2-85 Monthly volume of cleared and submitted INCs, DECs: January through September 2009 (See 2008 SOM, Table 2-85)

	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	13,986	21,401	423	621	16,879	26,080	487	670
Feb	13,487	22,228	484	739	15,557	24,967	420	624
Mar	13,364	22,639	552	820	15,186	23,243	459	651
Apr	11,363	19,935	380	645	13,900	21,173	428	607
May	12,853	16,863	388	750	13,973	19,274	529	805
Jun	12,375	15,369	315	750	14,777	18,402	482	802
Jul	12,187	17,654	314	821	14,554	19,322	483	808
Aug	12,347	22,931	433	1,020	16,626	23,788	641	1,069
Sep	13,936	22,417	459	993	16,736	23,268	480	957
Oct								
Nov								
Dec								
Annual	12,873	20,145	416	796	15,353	22,150	491	778

Demand-Side Response (DSR)

Emergency Program

Table 2-86 Zonal capability in the Emergency Program for the 2009 peak day through September (By option): August 10, 2009 (See 2008 SOM, Table 2-86)

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	131	45.7	12	15.9
AEP	0	0.0	588	1,259.9	99	504.3
AP	0	0.0	524	424.9	42	72.2
BGE	0	0.0	485	615.8	29	26.1
ComEd	0	0.0	805	646.6	526	697.1
DAY	0	0.0	159	147.5	13	57.2
DLCO	0	0.0	160	86.7	34	33.7
Dominion	0	0.0	445	473.4	46	40.6
DPL	0	0.0	168	123.0	15	39.5
JCPL	0	0.0	285	124.3	28	22.4
Met-Ed	0	0.0	174	182.3	42	42.2
PECO	0	0.0	414	136.5	235	215.3
PENELEC	0	0.0	248	192.7	45	27.6
Pepco	0	0.0	269	88.7	32	29.0
PPL	0	0.0	555	292.1	127	315.0
PSEG	0	0.0	582	286.8	79	26.0
RECO	0	0.0	15	3.0	6	0.5
Total	0	0.0	6,007	5,129.8	1,410	2,164.5

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Table 2-87 Zonal monthly capacity credits: January through September 2009 (See 2008 SOM, Table 2-87)

Zone	January	February	March	April	May	June	July	August	September
AECO	$154,551	$139,595	$154,551	$149,566	$154,551	$375,086	$387,589	$387,589	$375,086
AEP	$2,578,133	$2,328,636	$2,578,133	$2,494,967	$2,578,133	$3,746,728	$3,871,619	$3,871,619	$3,746,728
APS	$966,835	$873,270	$966,835	$935,647	$966,835	$2,982,596	$3,082,016	$3,082,016	$2,982,596
BGE	$2,882,161	$2,603,243	$2,882,161	$2,789,189	$2,882,161	$4,464,694	$4,613,517	$4,613,517	$4,464,694
ComEd	$3,294,602	$2,975,769	$3,294,602	$3,188,324	$3,294,602	$4,217,299	$4,357,876	$4,357,876	$4,217,299
DAY	$258,904	$233,849	$258,904	$250,552	$258,904	$646,419	$667,966	$667,966	$646,419
DLCO	$258,489	$233,474	$258,489	$250,151	$258,489	$375,138	$1,655,820	$1,655,820	$375,138
Dominion	$296,319	$267,643	$296,319	$286,760	$296,319	$1,602,407	$1,004,045	$1,004,045	$1,602,407
DPL	$665,561	$601,152	$665,561	$644,091	$665,561	$971,656	$387,642	$387,642	$971,656
JCPL	$554,279	$500,639	$554,279	$536,399	$554,279	$868,932	$897,896	$897,896	$868,932
Met-Ed	$681,734	$615,760	$681,734	$659,743	$681,734	$1,313,605	$1,357,392	$1,357,392	$1,313,605
PECO	$1,375,581	$1,242,460	$1,375,581	$1,331,207	$1,375,581	$2,052,483	$2,120,899	$2,120,899	$2,052,483
PENELEC	$283,241	$255,831	$283,241	$274,105	$283,241	$1,282,941	$1,324,705	$1,324,705	$1,282,941
Pepco	$572,160	$516,789	$572,160	$553,703	$572,160	$788,433	$814,714	$814,714	$788,433
PPL	$1,200,552	$1,084,370	$1,200,552	$1,161,825	$1,200,552	$3,500,850	$3,617,545	$3,617,545	$3,500,850
PSEG	$922,290	$833,036	$922,290	$892,538	$922,290	$1,720,276	$1,777,619	$1,777,619	$1,720,276
RECO	$10,219	$9,230	$10,219	$9,890	$10,219	$17,897	$18,494	$18,494	$17,897
Total	$16,955,611	$15,314,746	$16,955,611	$16,408,656	$16,955,611	$30,927,439	$31,957,354	$31,957,354	$30,927,439

Economic Program

Table 2-88 Economic Program registration on the last day of the month: January 2007 through September 2009[10,11] (New Table)

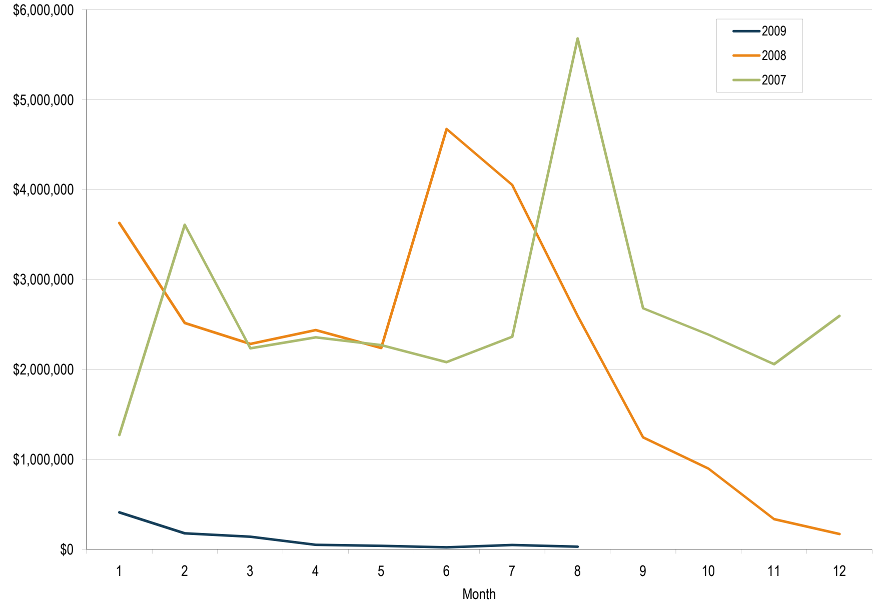
	2007		2008		2009	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303
Feb	953	1,567	4,902	2,961	4,869	3,219
Mar	959	1,578	4,972	3,012	4,867	3,227
Apr	980	1,648	5,016	3,197	2,582	3,242
May	996	3,674	5,069	3,588	1,250	2,860
Jun	2,490	2,168	3,112	3,014	1,265	2,461
Jul	2,872	2,459	4,542	3,165	1,265	2,445
Aug	2,911	2,582	4,815	3,232	1,653	2,650
Sep	4,868	2,915	4,836	3,263	1,879	2,727
Oct	4,873	2,880	4,846	3,266		
Nov	4,897	2,948	4,851	3,271		
Dec	4,898	2,944	4,851	3,290		
Avg.	2,684	2,408	4,727	3,185	2,721	2,904

10 The site count and registered MW associated with May 2007 are for May 9, 2007. Several new sites registered in May of 2007 overstated their MW capability, and it remains overstated in PJM data.
11 Table 2-88 reflects distinct registration counts. It does not reflect the number of distinct sites registered for the Economic Program, as multiple sites may be aggregated within a single registration.

Table 2-89 Distinct Registrations and Sites in the Economic Program: August 10, 2009[12] (See 2008 SOM, Table 2-89)

	Registrations	Sites	MW
AECO	38	38	17.7
AEP	15	15	201.7
AP	88	88	212.3
BGE	139	139	645.3
ComEd	318	318	276.4
DAY	5	5	10.6
DLCO	28	28	226.2
Dominion	93	93	131.2
DPL	67	67	71.1
JCPL	38	41	101.3
Met-Ed	41	41	60.9
PECO	160	160	147.0
PENELEC	39	39	31.2
Pepco	22	23	20.3
PPL	136	142	266.6
PSEG	91	92	65.8
RECO	3	3	1.0
Total	1,321	1,332	2,486.6

Figure 2-21 Economic Program Payments: Calendar years 2007 (without incentive payments), 2008 and January through September of 2009[13,14] (See 2008 SOM, Figure 2-20)



12 Effective July 1, 2009, PJM implemented a new eSuite application, Load Response System (eLRS) to serve as the interface for collecting and storing customer registration and settlement data. With the implementation of the LRS system, more detail is available on customer registrations and, as a result, there is an enhanced ability to capture multiple distinct locations aggregated to a single registration. The second column of Table 2-89 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

13 All August and September settlement, reduction and credit data are subject to change. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could result in a maximum lag of approximately 74 calendar days.

14 In the September billing cycle, PJM Market Settlements encountered an error in which prior settled amounts in the Economic Load Response Program were paid again for several CSPs. PJM Market Settlements notified all affected CSPs of the billing error and made the appropriate adjustments in the October 2009 bill. All Economic Load Response credit and reduction data in this report were provided by PJM as of October 13, 2009. Data in this report reflect the corrected amounts.

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Table 2-90 PJM Economic Program by zonal reduction: January through September 2009[15] (See 2008 SOM, Table 2-92)

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	38	$1,149	144				4	$117	15	43	$1,266	159
AEP	3,895	$53,692	247	1,317	$25,038	22				5,212	$78,730	269
AP	1,322	$27,046	251				10	$562	11	1,332	$27,608	262
BGE	49	$2,291	208							49	$2,291	208
ComEd	336	$316	146				723	$4,369	822	1,059	$4,684	968
DAY												
DLCO												
Dominion	4,597	$205,728	824	74	$674	44	155	$6,094	137	4,825	$212,496	1,005
DPL	10	$414	246							10	$414	246
JCPL							9	$248	30	9	$248	30
Met-Ed	66	$3,218	96				5	$255	17	72	$3,474	113
PECO	7,207	$153,200	12,332				213	$14,254	1,104	7,420	$167,454	13,436
PENELEC	863	$6,661	116				2	$47	6	865	$6,708	122
Pepco	131	$4,341	83				39	$1,753	71	170	$6,094	154
PPL	9,568	$319,582	3,586	2,182	$65,196	365	172	$14,954	336	11,922	$399,733	4,287
PSEG	296	$4,139	266				5	$177	32	301	$4,316	298
RECO	1	$12	24							1	$12	24
Total	28,381	$781,790	18,569	3,573	$90,909	431	1,337	$42,832	2,581	33,290	$915,530	21,581
Max	9,568	$319,582	12,332	2,182	$65,196	365	723	$14,954	1,104	11,922	$399,733	13,436
Avg	2,027	$55,842	1,326	1,191	$30,303	144	122	$3,894	235	2,219	$61,035	1,439

Table 2-91 Settlement days submitted by month in the Economic Program: 2007, 2008 and January through September 2009 (New Table)

Month	2007	2008	2009
Jan	937	2,916	1,264
Feb	1,170	2,811	654
Mar	1,255	2,818	574
Apr	1,540	3,406	337
May	1,649	3,336	918
Jun	1,856	3,184	2,727
Jul	2,534	3,339	2,879
Aug	3,962	3,848	3,760
Sep	3,388	3,264	2,570
Oct	3,508	1,977	
Nov	2,842	1,105	
Dec	2,675	986	
Total	26,423	32,316	15,683

15 While total credits in Table 2-90 for the period January through September 2009 match the Demand Response Steering Committee (DRSC) October 13, 2009 report, the number of MWh and the amount of credits identified as Real-Time Self-Scheduled, Real-Time Dispatch, and Day Ahead activities do not agree. Monitoring Analytics has requested that PJM verify results.

Table 2-92 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2007, 2008 and January through September 2009 (New Table)

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

Table 2-93 Hourly frequency distribution of Economic Program MWh reductions and credits: January through September 2009 (See 2008 SOM, Table 2-93)

	MWh Reductions				Program Credits			
Hour	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
1	450	1.35%	450	1.35%	$6,262	0.68%	$6,262	0.68%
2	462	1.39%	912	2.74%	$6,312	0.69%	$12,574	1.37%
3	492	1.48%	1,404	4.22%	$7,725	0.84%	$20,299	2.22%
4	518	1.56%	1,922	5.77%	$7,922	0.87%	$28,222	3.08%
5	535	1.61%	2,457	7.38%	$8,607	0.94%	$36,828	4.02%
6	565	1.70%	3,022	9.08%	$11,974	1.31%	$48,803	5.33%
7	1,691	5.08%	4,713	14.16%	$86,917	9.49%	$135,719	14.82%
8	2,073	6.23%	6,786	20.39%	$104,820	11.45%	$240,540	26.27%
9	1,944	5.84%	8,730	26.23%	$68,294	7.46%	$308,834	33.73%
10	1,661	4.99%	10,391	31.21%	$55,288	6.04%	$364,122	39.77%
11	1,561	4.69%	11,952	35.90%	$51,343	5.61%	$415,465	45.38%
12	1,483	4.45%	13,435	40.36%	$36,595	4.00%	$452,060	49.38%
13	1,527	4.59%	14,962	44.94%	$33,076	3.61%	$485,136	52.99%
14	1,719	5.16%	16,680	50.11%	$33,879	3.70%	$519,015	56.69%
15	1,643	4.94%	18,323	55.04%	$30,866	3.37%	$549,880	60.06%
16	1,714	5.15%	20,037	60.19%	$28,436	3.11%	$578,316	63.17%
17	1,996	6.00%	22,033	66.18%	$39,447	4.31%	$617,763	67.48%
18	2,233	6.71%	24,266	72.89%	$59,268	6.47%	$677,031	73.95%
19	2,153	6.47%	26,419	79.36%	$62,739	6.85%	$739,770	80.80%
20	2,089	6.28%	28,509	85.64%	$59,315	6.48%	$799,085	87.28%
21	1,901	5.71%	30,410	91.35%	$65,079	7.11%	$864,164	94.39%
22	1,298	3.90%	31,708	95.25%	$29,106	3.18%	$893,270	97.57%
23	868	2.61%	32,576	97.86%	$13,511	1.48%	$906,780	99.04%
24	714	2.14%	33,290	100.00%	$8,750	0.96%	$915,530	100.00%

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Table 2-94 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through September 2009 (See 2008 SOM, Table 2-94)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
$0 to $25	487	1.46%	487	1.46%	$300	0.03%	$300	0.03%
$25 to $50	17,241	51.79%	17,728	53.25%	$203,256	22.20%	$203,555	22.23%
$50 to $75	7,303	21.94%	25,031	75.19%	$163,412	17.85%	$366,967	40.08%
$75 to $100	3,949	11.86%	28,980	87.05%	$162,043	17.70%	$529,010	57.78%
$100 to $125	1,917	5.76%	30,896	92.81%	$116,528	12.73%	$645,538	70.51%
$125 to $150	1,162	3.49%	32,058	96.30%	$97,590	10.66%	$743,128	81.17%
$150 to $200	829	2.49%	32,887	98.79%	$98,745	10.79%	$841,872	91.95%
$200 to $250	334	1.00%	33,221	99.79%	$54,219	5.92%	$896,091	97.88%
$250 to $300	10	0.03%	33,231	99.82%	$2,248	0.25%	$898,339	98.12%
> $300	59	0.18%	33,290	100.00%	$17,192	1.88%	$915,530	100.00%

Load Management (LM)

Table 2-95 Available LM MW by program type: Delivery years 2007 through 2009 (New Table)

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	999.4	6,295.0	7,294.9

Table 2-96 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007 through 2012 (New Table)

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

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SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2009. 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 is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital 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 fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  Overall, through the first nine months of 2009, net revenue results were mixed compared to the same period in 2008. For the new entrant combustion turbine (CT), nine zones had lower net revenue and eight zones had higher net revenue compared to 2008. (Table 3-8) All zones had lower energy net revenue compared to 2008 for the new entrant CT, however, for zones that cleared in the RTO Locational Delivery Area (LDA) for the 2007/2008 and the 2008/2009 BRA, this decrease in energy net revenue was more than offset by higher capacity revenues in the 2008/2009 delivery year. For the new entrant combined cycle (CC), eleven zones had lower net revenue and six zones had higher net revenue compared to 2008, which reflects a decrease in energy market revenue in all zones, a decrease in capacity revenue in most eastern zones, and an increase in capacity revenues in western zones which more than offset lower energy net revenues in AEP, AP, ComEd, DAY and DLCO and PENELEC. For the new entrant coal plant (CP), all zones had a significant decrease in net revenue compared to 2008, which is driven by lower energy revenues.

  The levels of net revenue through September of 2009 for new peaking, midmerit and baseload power plants vary significantly by location. Energy market prices and delivered fuel prices are down from the same period in 2008, although the spread between fuel costs and energy market prices varies by location. In western zones, energy market prices decreased less than in eastern zones, and, as a result, eastern zones show a more significant decrease in net revenue for the CT and the CC technology compared to western zones. The decrease in net revenues for the CP technology in all zones reflects the fact that energy prices decreased more than the delivered price of coal compared to the same period in 2008. Capacity market revenues also show mixed results for the first nine months of 2009 compared to the same period in 2008. Zones in the RTO LDA show an increase in capacity revenues from the same period in 2008 as the RTO cleared significantly higher in the 2008/2009 BRA and the 2009/2010 BRA compared to the 2007/2008 BRA. Some zones in the east show a decrease in capacity revenues from the same period in 2008 as the 2007/2008 auction cleared at a higher price for eastern zones than the 2008/2009 auction. When capacity market revenues for the full year 2009 are reflected, all control zones will show an increase in capacity revenue compared to calendar year 2008. The results from January through September of 2009 illustrate that the profitability of, and thus the incentive to invest in power generation technologies is closely tied to changes in the spread between electricity market prices and input fuel market prices in specific locations. In addition, 2009 results highlight the importance of revenues from the capacity market when energy market net revenues are insufficient to recover fixed costs.

  Zonal net revenue reflects differences in locational energy prices and differences in locational capacity prices. The zonal variation in net revenue illustrates the substantial impact of location on economic incentives. While the 2009 net revenue using PJM real-time average locational marginal prices was $39,920 per MW-year for a CT, the zonal maximum net revenue was $70,637 in the Pepco Control Zone and the minimum was $30,105 in the ComEd Control Zone.[1] While the PJM average net revenue in 2009 was $67,705 per MW-year for a CC, the zonal maximum net revenue was $110,937 in the Pepco Control Zone and the minimum was $50,495 in the ComEd Control Zone. While the PJM average net revenue in 2008 was $77,054 per MW-year for a CP, the zonal maximum net revenue was $146,463 in the Pepco Control Zone and the minimum was $54,209 in the DAY Control Zone.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through September 30, 2009, PJM installed capacity resources rose slightly from 164,899 MW on January 1 to 167,269 MW on September 30.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of September 2009, 40.7 percent was coal; 29.2 percent was natural gas; 18.4 percent was nuclear; 6.4 percent was oil; 4.7 percent was hydroelectric; 0.4 percent was solid waste, and 0.2 percent was wind.

- **Generation Fuel Mix.** During January through September 2009, coal provided 50.3 percent, nuclear 35.8 percent, natural gas 10.1 percent, heavy oil 0.2 percent, hydroelectric 2.0 percent, solid waste 0.6 percent, miscellaneous 0.2 percent, landfill gas 0.2 percent, and wind 0.7 percent of total generation.

- **Planned Generation.** If current trends continue, it is expected that older steam units in the east will be replaced by units burning natural gas and the result has potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure.

Scarcity

- **Scarcity Pricing Events in 2009.** PJM did not declare a scarcity event in the first three quarters of 2009.

  Scarcity exists when demand plus reserve requirements approach the available generating capacity of the system. Scarcity pricing means that market prices reflect the fact that the system is using close to its available capacity and that competitive prices may exceed accounting short-run marginal costs. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail. As demand increases and units with higher offers are required to meet demand, prices increase.

  When available capacity is not sufficient to maintain reserves, system operators have to implement emergency measures to maintain reliable service. These emergency measures include voltage reductions, emergency energy purchases and calling on maximum emergency resources. All of these actions are designed preserve the level of reserves needed to maintain system reliability.

  Under the current PJM rules, administrative scarcity pricing results when PJM takes specific, non market, emergency administrative actions to maintain system reliability under conditions of high load in pre-specified areas within PJM. When PJM implements any of the identified emergency procedures, any offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

- **Scarcity.** A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules. The mandated reserve margin requires units that are called on only under relatively unusual load conditions, if at all. Thus, the energy market alone frequently does not directly compensate some of the resources needed to provide for reliability.

  Scarcity revenues to generation owners can come from a combination of energy and capacity markets or they can come entirely from capacity markets. The RPM capacity market design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed modification of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues.

1 Calculated values shown in Section 3, "Energy Market, Part 2," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

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The revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, energy market design should 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 is part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues.

Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs under well defined conditions with transparent and verifiable 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. With a capacity market design that appropriately reflects scarcity rents in the energy market through an offset 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.

Like an administrative energy market scarcity pricing mechanism, 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.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if scarcity revenues are provided in the energy market, there must be an explicit offset mechanism to remove those revenues from capacity market revenues or to ensure that the energy market scarcity revenues are not paid to capacity resources. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecast by analysts from any organization. The absence of such a mechanism is likely to result in an over collection of scarcity revenues as such revenues are episodic and unlikely to be fully reflected in forward curves, even if such curves were based on a liquid market three years forward and reflected locational results, which they do not. The most straightforward way to ensure that such over collection does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

- **Modifications to Scarcity Pricing.** While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, PJM's scarcity pricing rules need refinement.

  The current single scarcity price signal should be replaced by locational signals. Locational scarcity signals could be implemented via ten minute reserve requirements modeled as constraints within reserve requirement regions, with administrative scarcity penalty factors, in the security constrained dispatch. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes.

  The objective should be to create a system that recognizes scarcity in needed reserves, that redispatches units to maintain needed reserves and to meet the need for energy and that provides market signals consistent with this redispatch and with any failure to maintain needed reserves.

  The reserve requirement mechanism should use clearly defined reserve targets and accurate measurement of the resources available to meet those requirements. Accurate measurement of available resources is an essential element of a reserve requirement based scarcity pricing mechanism. Without accurate measurement of available reserves, any mechanism designed to dispatch the system to maintain reserves will be compromised in both efficiency and effectiveness. PJM needs to develop better measurements of available primary reserves prior to implementing a resource constraint based scarcity pricing mechanism as current measures are not adequate. To be effective, operators will need accurate, real time data on unit availability and capabilities, including better data on ramp rates and ambient temperature adjustments.

  Any scarcity pricing mechanism should also include an explicit, transparent set of rules governing the recall of energy produced by capacity resources and the defined conditions under which such recalls will occur.

To avoid market power, the provision of reserves must continue to be based on unit characteristics included in a participant's energy offers, not on the basis of separate offers to provide reserves. Allowing for separate energy and reserve offers would create inconsistent parameters, which would prevent the direct substitutability of unit capabilities between reserves and energy and create the potential for the exercise of market power.

The reserve penalty factor curve methodology also requires a mechanism to eliminate the effect of non-market administrative emergency measures used during scarcity situations. In the absence of such a mechanism, emergency actions would result in lower prices in the presence of worsening scarcity conditions. The mechanism would increase the reserve requirement by the amount of resources that result from the emergency actions in order to maintain a market signal consistent with the level of scarcity absent the emergency action. In order to implement this mechanism, PJM will need accurate measurements of the impact of the emergency steps.

This mechanism should apply only to non-market emergency actions. The mechanism should not be applied to emergency resources that have been purchased and have a recognized market value, in particular maximum emergency generation, emergency load response and recallable capacity backed exports. Under conditions of potential and actual emergency, such resources should be recognized as energy or reserves. In addition, such inclusion eliminates the incentive to designate capacity as emergency or to export energy during emergency conditions and thereby force scarcity conditions and higher prices.

The reserve penalty factor curve approach permits the offset of scarcity revenues for capacity resources in an exact manner. In the reserve penalty factor curve approach, scarcity revenues result from a defined scarcity adder.

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 operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in 2009.** The level of operating reserve credits and corresponding charges decreased in the months of January through September by 30.7 percent compared to the months of January through September 2008. This decrease was comprised of a large decrease in the amount of balancing operating reserve credits, an increase in day-ahead credits, and a decrease of 29.0 percent in synchronous condensing credits.

- **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.

- **Parameter Limited Schedule rules.** On March 19, 2009, the Commission issued an order rejecting PJM's proposed revisions to Section 6.6(c) of Schedule 1 of the PJM Operating Agreement that would have altered the application of the rules for evaluating requests for exceptions to the values included in or derived on a formulaic basis from the Parameter Limited Schedule Matrix.[2] As a consequence, the business rules approved by the Members Committee on November 15, 2007, were reinstated. PJM and the Market Monitor jointly administered these rules for the spring cycle.

2 126 FERC ¶61,251 (2009).

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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 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 in well-defined stages 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. With a capacity market design that appropriately reflects a direct and explicit offset for scarcity rents in the energy market, 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.

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, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

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.

In January through September of 2009, energy market revenues were lower as a result of lower energy prices in all zones compared to the same period in 2008. However, the cost of input fuels was also down significantly from the prior period, resulting in lower marginal costs for all technologies. The change in energy market net revenue is a function of the change in locational price levels and fuel costs. As a result, the change in energy market net revenue for the first nine months of 2009 compared to the first nine months of 2008 varies significantly by fuel type, technology and location.

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 are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in the first nine months of 2009. Scarcity revenues in the energy market contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the Capacity Market. However, when the actual fixed costs of capacity increase rapidly, or, when energy net revenues available for new entrants decreases

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rapidly, 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 CTs set price based on gas costs. In January through September of 2009, with generally lower load levels, CTs ran less often, which reduced the net revenue received by coal plants.

Net Revenue

Capacity Market Net Revenue

Table 3-1 2009 Calendar Year PJM RPM auction-clearing capacity prices and capacity revenues by LDA and zone: Effective for January through September 2009 (See 2008 SOM, Table 3-3)

	Delivery Year 2008/2009			Delivery Year 2009/2010			RPM Revenue 2009
Zone	LDA	$/MW-Day	$/MW in 2009	LDA	$/MW-Day	$/MW in 2009	(Jan - Sep) $/MW
AECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
AEP	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
AP	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
BGE	SWMAAC	$210.11	$31,727	SWMAAC	$237.33	$28,954	$60,681
ComEd	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
DAY	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
DLCO	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
Dominion	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
DPL	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
JCPL	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
Met-Ed	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
PECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
PENELEC	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
Pepco	SWMAAC	$210.11	$31,727	SWMAAC	$237.33	$28,954	$60,681
PPL	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
PSEG	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
RECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
PJM	N/A	$124.58	$18,812	N/A	$138.46	$16,892	$35,703

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through September 2009 (See 2008 SOM, Table 3-4)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$48,199	$45,810	(5%)
AEP	$19,856	$29,349	48%
AP	$19,856	$40,241	103%
BGE	$54,292	$60,681	12%
ComEd	$19,856	$29,349	48%
DAY	$19,856	$29,349	48%
DLCO	$19,856	$29,349	48%
Dominion	$19,856	$29,349	48%
DPL	$48,199	$45,810	(5%)
JCPL	$48,199	$45,810	(5%)
Met-Ed	$19,856	$40,241	103%
PECO	$48,199	$45,810	(5%)
PENELEC	$19,856	$40,241	103%
Pepco	$54,292	$60,681	12%
PPL	$19,856	$40,241	103%
PSEG	$48,199	$45,810	(5%)
RECO	$48,199	$45,810	(5%)
PJM	$28,588	$35,703	25%

New Entrant Net Revenues

Table 3-3 Average delivered fuel price in PJM (Dollars per MBtu): January through September 2008 and 2009 (See 2008 SOM, Table 3-6)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
Natural Gas	$10.80	$4.67	(57%)
Low Sulfur Coal	$4.53	$3.23	(29%)

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Table 3-4 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Net revenue for January through September 2008 and 2009 (See 2008 SOM, Table 3-7)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$60,950	$9,926	(84%)
AEP	$4,695	$3,576	(24%)
AP	$20,690	$12,728	(38%)
BGE	$45,137	$13,083	(71%)
ComEd	$4,393	$2,751	(37%)
DAY	$5,124	$3,279	(36%)
DLCO	$7,785	$4,371	(44%)
Dominion	$37,629	$13,971	(63%)
DPL	$32,794	$12,358	(62%)
JCPL	$33,417	$10,084	(70%)
Met-Ed	$24,746	$9,122	(63%)
PECO	$25,716	$8,781	(66%)
PENELEC	$5,590	$3,552	(36%)
Pepco	$46,690	$15,361	(67%)
PPL	$20,717	$8,091	(61%)
PSEG	$27,633	$9,850	(64%)
RECO	$23,148	$8,441	(64%)
PJM	$12,445	$4,903	(61%)

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 2008 and 2009 (See 2008 SOM, Table 3-7)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$136,158	$44,929	(67%)
AEP	$26,445	$25,240	(5%)
AP	$66,752	$50,300	(25%)
BGE	$120,486	$48,717	(60%)
ComEd	$26,228	$20,543	(22%)
DAY	$28,400	$25,433	(10%)
DLCO	$26,843	$24,883	(7%)
Dominion	$105,147	$51,278	(51%)
DPL	$102,291	$48,316	(53%)
JCPL	$111,689	$45,154	(60%)
Met-Ed	$88,762	$40,482	(54%)
PECO	$90,696	$40,367	(55%)
PENELEC	$38,602	$26,425	(32%)
Pepco	$120,454	$50,716	(58%)
PPL	$82,087	$38,245	(53%)
PSEG	$105,588	$47,849	(55%)
RECO	$95,823	$43,610	(54%)
PJM	$55,969	$29,614	(47%)

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 2008 and 2009 (See 2008 SOM, Table 3-7)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$309,767	$81,049	(74%)
AEP	$136,544	$41,463	(70%)
AP	$231,731	$81,877	(65%)
BGE	$282,747	$73,912	(74%)
ComEd	$182,016	$68,512	(62%)
DAY	$118,189	$26,274	(78%)
DLCO	$128,065	$51,590	(60%)
Dominion	$260,411	$68,799	(74%)
DPL	$287,512	$56,580	(80%)
JCPL	$293,173	$80,212	(73%)
Met-Ed	$257,848	$71,696	(72%)
PECO	$264,203	$76,509	(71%)
PENELEC	$214,546	$82,351	(62%)
Pepco	$298,582	$78,240	(74%)
PPL	$260,572	$79,695	(69%)
PSEG	$231,512	$103,097	(55%)
RECO	$280,621	$77,192	(72%)
PJM	$167,110	$43,763	(74%)

New Entrant Combustion Turbine

Table 3-7 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-10)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
Energy	$12,445	$4,903	(61%)
Capacity	$25,477	$31,818	25%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,199	$1,199	0%
Total	$39,121	$37,920	(3%)

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 2008 and 2009 (See 2008 SOM, Table 3-11)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$105,103	$51,950	(51%)
AEP	$23,589	$30,929	31%
AP	$39,584	$49,788	26%
BGE	$94,719	$68,359	(28%)
ComEd	$23,287	$30,105	29%
DAY	$24,018	$30,632	28%
DLCO	$26,679	$31,725	19%
Dominion	$56,523	$41,325	(27%)
DPL	$76,947	$54,382	(29%)
JCPL	$77,570	$52,107	(33%)
Met-Ed	$43,640	$46,183	6%
PECO	$69,869	$50,804	(27%)
PENELEC	$24,484	$40,612	66%
Pepco	$96,272	$70,637	(27%)
PPL	$39,611	$45,152	14%
PSEG	$71,786	$51,874	(28%)
RECO	$67,301	$50,465	(25%)
PJM	$39,121	$37,920	(3%)

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New Entrant Combined Cycle

Table 3-9 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-12)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
Energy	$55,969	$29,614	(47%)
Capacity	$27,618	$34,492	25%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,599	$1,599	0%
Total	$85,186	$65,705	(23%)

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 2008 and 2009 (See 2008 SOM, Table 3-13)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$184,321	$90,783	(51%)
AEP	$47,226	$55,192	17%
AP	$87,533	$90,774	4%
BGE	$174,534	$108,938	(38%)
ComEd	$47,009	$50,495	7%
DAY	$49,181	$55,386	13%
DLCO	$47,624	$54,835	15%
Dominion	$125,929	$81,230	(35%)
DPL	$150,455	$94,170	(37%)
JCPL	$159,852	$91,008	(43%)
Met-Ed	$109,543	$80,957	(26%)
PECO	$138,859	$86,222	(38%)
PENELEC	$59,383	$66,900	13%
Pepco	$174,502	$110,937	(36%)
PPL	$102,869	$78,720	(23%)
PSEG	$153,751	$93,704	(39%)
RECO	$143,986	$89,465	(38%)
PJM	$85,186	$65,705	(23%)

New Entrant Coal Plant

Table 3-11 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-14)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
Energy	$167,110	$43,763	(74%)
Capacity	$25,774	$32,189	25%
Synchronized	$0	$0	0%
Regulation	$752	$210	(72%)
Reactive	$892	$892	0%
Total	$194,527	$77,054	(60%)

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 2008 and 2009 (See 2008 SOM, Table 3-15)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$355,209	$124,194	(65%)
AEP	$156,146	$69,792	(55%)
AP	$251,798	$120,187	(52%)
BGE	$333,659	$130,119	(61%)
ComEd	$202,313	$96,983	(52%)
DAY	$137,649	$54,209	(61%)
DLCO	$147,945	$80,119	(46%)
Dominion	$280,374	$96,873	(65%)
DPL	$332,986	$99,010	(70%)
JCPL	$338,536	$123,344	(64%)
Met-Ed	$277,699	$109,647	(61%)
PECO	$309,653	$119,671	(61%)
PENELEC	$234,601	$120,751	(49%)
Pepco	$349,584	$134,559	(62%)
PPL	$280,458	$117,901	(58%)
PSEG	$276,760	$146,463	(47%)
RECO	$326,057	$120,281	(63%)
PJM	$194,527	$77,054	(60%)

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 2008 and 2009 (See 2008 SOM, Table 3-16)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$24,969	$9,926	(60%)
AEP	$1,901	$3,576	88%
AP	$9,409	$12,728	35%
BGE	$27,451	$13,083	(52%)
ComEd	$1,863	$2,751	48%
DAY	$1,851	$3,195	73%
DLCO	$1,550	$4,371	182%
Dominion	$18,344	$13,971	(24%)
DPL	$18,643	$12,358	(34%)
JCPL	$14,060	$10,084	(28%)
Met-Ed	$12,655	$9,122	(28%)
PECO	$12,734	$8,781	(31%)
PENELEC	$4,465	$3,552	(20%)
Pepco	$29,223	$15,361	(47%)
PPL	$10,412	$8,091	(22%)
PSEG	$13,858	$9,850	(29%)
RECO	$11,521	$8,441	(27%)
PJM	$6,644	$1,896	(71%)

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 2008 and 2009 (See 2008 SOM, Table 3-17)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$97,526	$44,929	(54%)
AEP	$20,861	$25,240	21%
AP	$53,132	$50,300	(5%)
BGE	$105,588	$48,717	(54%)
ComEd	$21,635	$20,543	(5%)
DAY	$21,322	$25,399	19%
DLCO	$16,049	$24,883	55%
Dominion	$87,683	$51,278	(42%)
DPL	$86,229	$48,316	(44%)
JCPL	$97,496	$45,154	(54%)
Met-Ed	$74,945	$40,482	(46%)
PECO	$74,654	$40,367	(46%)
PENELEC	$35,689	$26,425	(26%)
Pepco	$108,603	$50,716	(53%)
PPL	$68,759	$38,245	(44%)
PSEG	$93,059	$47,849	(49%)
RECO	$84,920	$43,610	(49%)
PJM	$43,044	$27,186	(37%)

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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 2008 and 2009 (See 2008 SOM, Table 3-18)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$293,296	$81,049	(72%)
AEP	$135,380	$41,463	(69%)
AP	$226,934	$81,877	(64%)
BGE	$283,802	$73,912	(74%)
ComEd	$187,687	$68,512	(63%)
DAY	$114,894	$26,818	(77%)
DLCO	$131,603	$51,590	(61%)
Dominion	$254,955	$68,799	(73%)
DPL	$290,021	$56,580	(80%)
JCPL	$295,885	$80,212	(73%)
Met-Ed	$261,220	$71,696	(73%)
PECO	$270,026	$76,509	(72%)
PENELEC	$226,578	$82,351	(64%)
Pepco	$301,912	$78,240	(74%)
PPL	$264,827	$79,695	(70%)
PSEG	$232,779	$103,097	(56%)
RECO	$283,203	$77,192	(73%)
PJM	$162,107	$41,054	(75%)

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008 and January through September 2009 (See 2008 SOM, Table 3-19)

	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 (Jan - Sep)	$4,903	$1,896	$3,007	61%

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 years 2000 to 2008 and January through September 2009 (See 2008 SOM, Table 3-20)

	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 (Jan - Sep)	$29,614	$27,186	$2,428	8%

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 years 2000 to 2008 and January through September 2009 (See 2008 SOM, Table 3-21)

	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 (Jan - Sep)	$43,763	$41,054	$2,709	6%

Net Revenue Adequacy

Table 3-19 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)) (See 2008 SOM, Table 3-22)

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

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 2008 and 2009 (See 2008 SOM, Table 3-24)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	20-Year Levelized Fixed Cost	2008 Percent Recovery	2009 Percent Recovery
AECO	$105,103	$51,950	$123,640	85%	42%
AEP	$23,589	$30,929	$123,640	19%	25%
AP	$39,584	$49,788	$123,640	32%	40%
BGE	$94,719	$68,359	$123,640	77%	55%
ComEd	$23,287	$30,105	$123,640	19%	24%
DAY	$24,018	$30,632	$123,640	19%	25%
DLCO	$26,679	$31,725	$123,640	22%	26%
Dominion	$56,523	$41,325	$123,640	46%	33%
DPL	$76,947	$54,382	$123,640	62%	44%
JCPL	$77,570	$52,107	$123,640	63%	42%
Met-Ed	$43,640	$46,183	$123,640	35%	37%
PECO	$69,869	$50,804	$123,640	57%	41%
PENELEC	$24,484	$40,612	$123,640	20%	33%
Pepco	$96,272	$70,637	$123,640	78%	57%
PPL	$39,611	$45,152	$123,640	32%	37%
PSEG	$71,786	$51,874	$123,640	58%	42%
RECO	$67,301	$50,465	$123,640	54%	41%
PJM	$39,121	$37,920	$123,640	32%	31%

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Figure 3-1 New entrant CT zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-3)

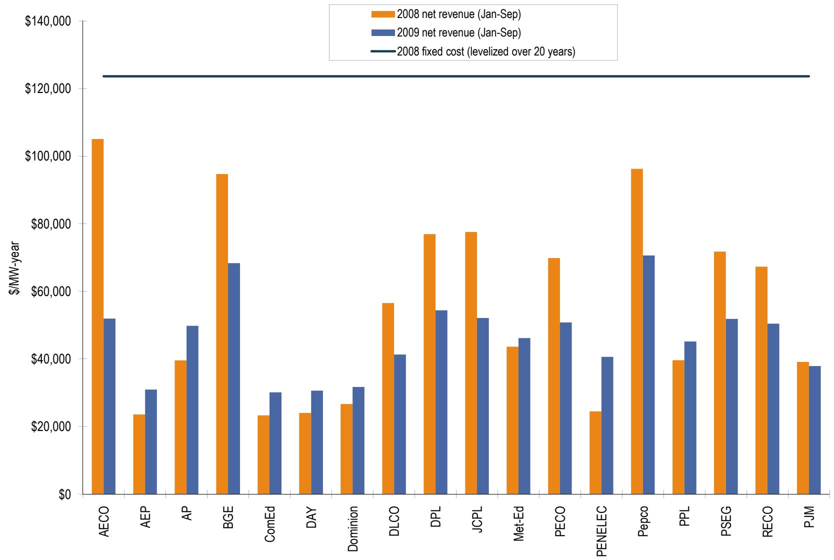

Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-26)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	20-Year Levelized Fixed Cost	2008 Percent Recovery	2009 Percent Recovery
AECO	$184,321	$90,783	$171,361	108%	53%
AEP	$47,226	$55,192	$171,361	28%	32%
AP	$87,533	$90,774	$171,361	51%	53%
BGE	$174,534	$108,938	$171,361	102%	64%
ComEd	$47,009	$50,495	$171,361	27%	29%
DAY	$49,181	$55,386	$171,361	29%	32%
DLCO	$47,624	$54,835	$171,361	28%	32%
Dominion	$125,929	$81,230	$171,361	73%	47%
DPL	$150,455	$94,170	$171,361	88%	55%
JCPL	$159,852	$91,008	$171,361	93%	53%
Met-Ed	$109,543	$80,957	$171,361	64%	47%
PECO	$138,859	$86,222	$171,361	81%	50%
PE-NELEC	$59,383	$66,900	$171,361	35%	39%
Pepco	$174,502	$110,937	$171,361	102%	65%
PPL	$102,869	$78,720	$171,361	60%	46%
PSEG	$153,751	$93,704	$171,361	90%	55%
RECO	$143,986	$89,465	$171,361	84%	52%
PJM	$85,186	$65,705	$171,361	50%	38%

Figure 3-2 New entrant CC zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-5)

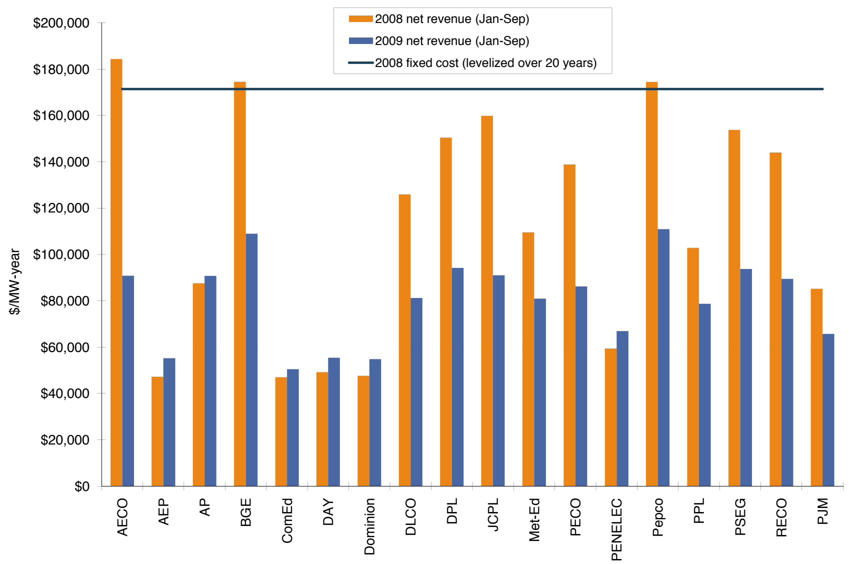

Figure 3-3 New entrant CP zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-7)

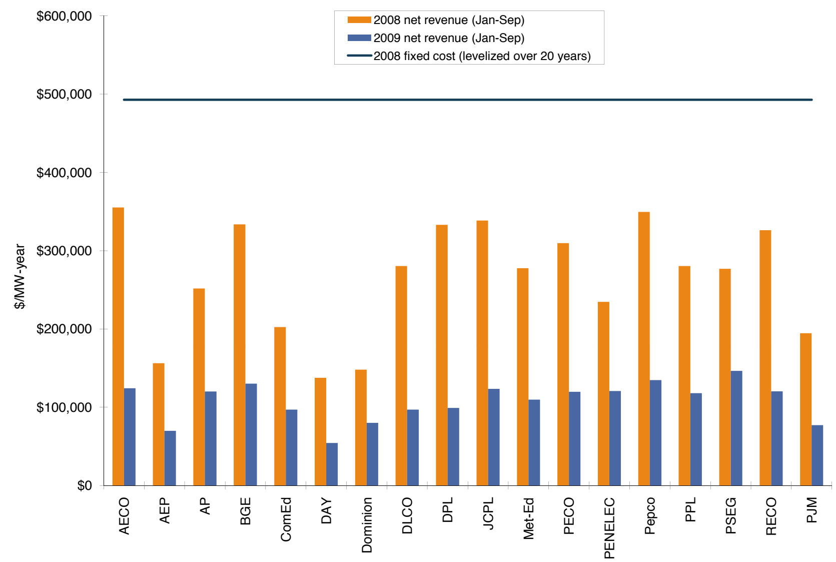

Table 3-22 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-28)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	20-Year Levelized Fixed Cost	2008 Percent Recovery	2009 Percent Recovery
AECO	$355,209	$124,194	$492,780	72%	25%
AEP	$156,146	$69,792	$492,780	32%	14%
AP	$251,798	$120,187	$492,780	51%	24%
BGE	$333,659	$130,119	$492,780	68%	26%
ComEd	$202,313	$96,983	$492,780	41%	20%
DAY	$137,649	$54,209	$492,780	28%	11%
DLCO	$147,945	$80,119	$492,780	30%	16%
Dominion	$280,374	$96,873	$492,780	57%	20%
DPL	$332,986	$99,010	$492,780	68%	20%
JCPL	$338,536	$123,344	$492,780	69%	25%
Met-Ed	$277,699	$109,647	$492,780	56%	22%
PECO	$309,653	$119,671	$492,780	63%	24%
PENELEC	$234,601	$120,751	$492,780	48%	25%
Pepco	$349,584	$134,559	$492,780	71%	27%
PPL	$280,458	$117,901	$492,780	57%	24%
PSEG	$276,760	$146,463	$492,780	56%	30%
RECO	$326,057	$120,281	$492,780	66%	24%
PJM	$194,527	$77,054	$492,780	39%	16%

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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, September 30, 2009 (See 2008 SOM, Table 3-30)[3, 4]

	1-Jan-09		31-May-09		1-Jun-09		30-Sep-09	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,064.7	40.7%	67,025.3	40.6%	68,159.0	40.7%	68,137.6	40.7%
Gas	48,333.9	29.3%	48,506.9	29.4%	48,979.3	29.2%	48,810.6	29.2%
Hydroelectric	7,476.3	4.5%	7,550.1	4.6%	7,939.9	4.7%	7,939.9	4.7%
Nuclear	30,478.0	18.5%	30,542.5	18.5%	30,701.5	18.3%	30,701.5	18.4%
Oil	10,714.9	6.5%	10,674.3	6.5%	10,704.3	6.4%	10,700.1	6.4%
Solid waste	664.7	0.4%	664.7	0.4%	672.1	0.4%	672.1	0.4%
Wind	166.4	0.1%	182.9	0.1%	297.8	0.2%	306.9	0.2%
Total	164,898.9	100.0%	165,146.7	100.0%	167,453.9	100.0%	167,268.7	100.0%

Energy Production by Primary Fuel Source

Table 3-24 PJM generation (By fuel source (GWh)): January through September 2009 (See 2008 SOM, Table 3-31)

	GWh	Percent
Coal	263,486.1	50.3%
Nuclear	187,626.8	35.8%
Natural Gas	52,694.5	10.1%
Hydroelectric	10,280.2	2.0%
Wind	3,446.5	0.7%
Solid Waste	3,125.5	0.6%
Miscellaneous	1,176.3	0.2%
Heavy Oil	1,127.0	0.2%
Landfill Gas	1,007.9	0.2%
Light Oil	156.5	0.0%
Kerosene	7.0	0.0%
Solar	2.9	0.0%
Biomass Gas	2.1	0.0%
Battery	0.1	0.0%
Jet Oil	0.0	0.0%
Total	524,139.5	100.0%

3 The capacity described in this section is the capability of all PJM capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

4 Wind-based resources accounted for 306.9 MW of installed capacity in PJM on September 30, 2009. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data in place of the 13 percent factor. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

Planned Generation Additions

Table 3-25 Year-to-year capacity additions: Calendar years 2000 through September 2009 (See 2008 SOM, Table 3-32)

	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	702

PJM Generation Queues

Table 3-26 Queue comparison (MW): Calendar years 2009 vs. 2008 (See 2008 SOM, Table 3-33)

	MW in the Queue 2008	MW in the Queue 2009	Year-to-Year Change (MW)	Year-to-Year Change
2009	9,023	10,137	1,114	11%
2010	18,052	14,409	(3,642)	(25)%
2011	17,253	16,276	(977)	(6)%
2012	15,527	11,330	(4,198)	(37)%
2013	7,920	7,263	(657)	(9)%
2014	11,965	12,329	364	3%
2015	2,436	1,861	(575)	(31)%
2016	0	2,590	2,590	100%
2017	0	1,640	1,640	100%
2018	1,594	1,594	0	0%
Total	83,770	79,429	(4,341)	(5)%

Table 3-27 Capacity in PJM queues (MW): At September 30, 2009[5, 6] (See 2008 SOM, Table 3-34)

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,121	0	17,347	25,468
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	319	186	3,978	4,482
N Expired 31-Jan-05	1,462	2,133	138	6,663	10,397
O Expired 31-Jul-05	2,203	748	792	3,831	7,574
P Expired 31-Jan-06	2,321	816	1,761	3,588	8,486
Q Expired 31-Jul-06	3,226	707	4,339	6,433	14,705
R Expired 31-Jan-07	7,893	667	294	13,987	22,840
S Expired 31-Jul-07	7,671	760	1,689	10,773	20,892
T Expired 31-Jan-08	17,123	158	319	10,867	28,466
U Expired 31-Jan-09	16,241	89	30	18,473	34,833
V Expires 31-Jan-10	10,889	0	2	809	11,701
Total	69,048	23,031	10,381	185,737	288,197

5 The *2009 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.

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Distribution of Units in the Queues

Table 3-28 Capacity additions in active or under-construction queues by control zone (MW): At September 30, 2009 (See 2008 SOM, Table 3-36)[7]

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unkn	Total
AECO	0	767	4	0	0	81	665	1,066	0	2,582
AEP	1,035	594	2	100	84	25	3,673	10,321	53	15,888
AP	930	4	0	139	0	0	724	2,216	0	4,013
BGE	220	256	5	0	1,640	1	0	0	132	2,254
ComEd	1,680	1,044	94	0	392	0	1,326	23,988	44	28,568
DAY	0	10	2	0	0	20	12	897	0	941
DLCO	0	0	0	77	91	0	0	0	0	168
DPL	0	55	0	0	0	6	43	450	0	554
Dominion	3,521	181	31	30	1,944	20	425	230	0	6,382
JCPL	1,430	27	33	1	0	53	0	0	0	1,543
Met-Ed	1,745	122	26	0	24	10	10	0	0	1,937
PECO	1,830	45	6	0	180	1	18	0	1	2,081
PENELEC	0	65	18	32	0	0	50	1,827	0	1,993
Pepco	2,670	249	5	0	1,640	0	0	0	20	4,584
PPL	1,400	137	3	143	1,600	26	266	226	0	3,800
PSEG	1,225	822	3	0	0	91	0	0	0	2,141
Total	17,686	4,378	233	521	7,595	334	7,211	41,221	250	79,429

Table 3-29 Existing PJM capacity on September 30, 2009 (By zone and unit type (MW)) (See 2008 SOM, Table 3-37)

	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
AECO	0	0	641	23	0	0	1,257	0	8	1,928
AEP	0	4,355	3,627	57	1,001	2,106	21,255	0	400	32,802
AP	0	1,129	1,140	36	108	0	7,974	0	245	10,632
BGE	0	0	862	7	0	1,735	2,942	0	0	5,546
ComEd	0	1,836	7,217	108	0	10,336	7,094	0	1,193	27,784
DAY	0	0	1,377	53	0	0	3,551	0	0	4,981
DLCO	0	0	0	0	6	1,741	1,259	0	0	3,006
DPL	0	364	2,487	95	0	0	2,016	0	0	4,962
Dominion	0	3,216	3,786	156	3,325	3,425	8,479	0	0	22,386
External	0	974	1,890	0	0	439	9,314	0	185	12,802
JCPL	0	1,078	1,430	25	400	615	318	0	0	3,865
Met-Ed	0	2,000	407	24	20	786	890	0	0	4,127
PECO	1	2,540	833	7	1,642	4,488	2,129	3	0	11,643
PENELEC	0	0	287	47	521	0	6,830	0	294	7,979
Pepco	0	0	1,454	9	0	0	4,829	0	0	6,292
PPL	0	960	1,352	63	571	2,275	5,830	0	217	11,268
PSEG	0	2,921	2,852	0	5	3,553	1,656	0	0	10,987
Total	1	21,373	31,640	711	7,599	31,499	87,621	3	2,542	182,988

Table 3-30 PJM capacity age (MW) (See 2008 SOM, Table 3-38)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,866	19,832	404	52	0	1,357	3	2,542	42,057
10 to 20	0	3,349	4,086	121	37	1,134	7,779	0	0	16,505
20 to 30	0	158	20	20	3,177	14,847	9,046	0	0	27,268
30 to 40	0	0	5,924	48	451	15,518	35,515	0	0	57,456
40 to 50	0	0	1,778	115	2,470	0	21,074	0	0	25,437
50 to 60	0	0	0	4	348	0	12,211	0	0	12,563
60 to 70	0	0	0	0	107	0	491	0	0	598
70 to 80	0	0	0	0	239	0	149	0	0	388
80 to 90	0	0	0	0	492	0	0	0	0	492
90 to 100	0	0	0	0	194	0	0	0	0	194
100 and over	0	0	0	0	32	0	0	0	0	32
Total	1	21,373	31,640	711	7,599	31,499	87,621	3	2,542	182,988

7 The unknown column includes MW data for units for which PJM has not provided the unit type.

Table 3-31 Capacity additions in active or under-construction queues by LDA (MW): At September 30, 2009 (See 2008 SOM, Table 3-39)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	4,485	1,716	46	1	180	232	726	1,516	1	8,902
Non-MAAC	7,166	1,833	129	346	2,511	65	6,160	37,651	97	55,959
SWMAAC	2,890	505	10	0	3,280	1	0	0	152	6,838
WMAAC	3,145	324	48	175	1,624	36	326	2,053	0	7,730
Total	17,686	4,378	233	521	7,595	334	7,211	41,221	250	79,429

Table 3-32 Comparison of generators 40 years and older with planned capacity additions (MW): Through 2018[8] (See 2008 SOM, Table 3-40)

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%	1	2	0.0%
	Combined Cycle	0	0.0%	6,903	20.7%	4,485	11,388	29.8%
	Combustion Turbine	634	10.4%	8,242	24.7%	1,716	9,324	24.4%
	Diesel	49	0.8%	150	0.4%	46	147	0.4%
	Hydroelectric	2,042	33.4%	2,047	6.1%	1	2,048	5.4%
	Nuclear	0	0.0%	8,656	25.9%	180	8,836	23.1%
	Solar	0	0.0%	3	0.0%	232	235	0.6%
	Steam	3,384	55.4%	7,376	22.1%	726	4,717	12.3%
	Wind	0	0.0%	8	0.0%	1,516	1,524	4.0%
	EMAAC Total	6,109	100.0%	33,385	100.0%	8,902	38,220	100.0%
Non-MAAC	Combined Cycle	0	0.0%	11,510	10.1%	7,166	18,675	12.7%
	Combustion Turbine	631	2.5%	19,037	16.6%	1,833	20,239	13.8%
	Diesel	34	0.1%	409	0.4%	129	505	0.3%
	Hydroelectric	1,396	5.6%	4,440	3.9%	346	4,786	3.3%
	Nuclear	0	0.0%	18,047	15.8%	2,511	20,558	14.0%
	Solar	0	0.0%	0	0.0%	65	65	0.0%
	Steam	23,002	91.8%	58,926	51.5%	6,160	42,084	28.7%
	Wind	0	0.0%	2,023	1.8%	37,651	39,675	27.0%
	Unknown	0	0.0%	0	0.0%	97	97	0.1%
	Non-MAAC Total	25,063	100.0%	114,392	100.0%	55,959	146,684	100.0%

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

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(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
SWMAAC	Combined Cycle	0	0.0%	0	0.0%	2,890	2,890	9633.3%
	Combustion Turbine	315	9.0%	2,316	19.6%	505	2,506	16.5%
	Diesel	0	0.0%	16	54.8%	10	26	88.1%
	Nuclear	0	0.0%	1,735	14.7%	3,280	5,015	33.0%
	Solar	0	0.0%	0	0.0%	1	1	4.0%
	Steam	3,169	91.0%	7,770	65.6%	0	4,602	30.3%
	Unknown	0	0.0%	0	0.0%	152	152	1.0%
	SWMAAC Total	3,484	100.0%	11,837	100.0%	6,838	15,192	100.0%
WMAAC	Combined Cycle	0	0.0%	2,960	12.7%	3,145	6,105	23.0%
	Combustion Turbine	198	3.9%	2,046	8.8%	324	2,172	8.2%
	Diesel	35	0.7%	135	0.6%	48	147	0.6%
	Hydroelectric	444	8.8%	1,112	4.8%	175	1,286	4.9%
	Nuclear	0	0.0%	3,061	13.1%	1,624	4,685	17.7%
	Solar	0	0.0%	0	0.0%	36	36	0.1%
	Steam	4,370	86.6%	13,549	58.0%	326	9,505	35.9%
	Wind	0	0.0%	511	2.2%	2,053	2,564	9.7%
	WMAAC Total	5,047	100.0%	23,373	100.0%	7,730	26,500	100.0%
All Areas	Total	39,703		182,988		79,429	226,596	

Characteristics of Wind Units

Table 3-33 Capacity factor of wind units in PJM, January through September 2009[9] (New Table)

Type of Resource	Capacity Factor	Total Hours	Installed Capacity
Energy-Only Resource	24.9%	122,624	1,744
Capacity Resource	27.5%	69,361	798
All Units	26.0%	191,985	2,542

Table 3-34 Wind resources in Real-Time offering at a negative price in PJM, June through September 2009[10] (New Table)

	Average MW Offered Daily	Intervals Marginal	Percent of All Intervals
At Negative Price	83.0	85	0.15%
All Wind	828.9	473	0.81%

9 The corresponding table in the *2009 Quarterly State of the Market Report for PJM*, reversed the labels for energy-only resources and capacity resources data..

10 Units were permitted to submit negative price offers beginning June 1, 2009.

Figure 3-4 Average hourly real-time generation of wind units in PJM, January through September 2009 (New Figure)

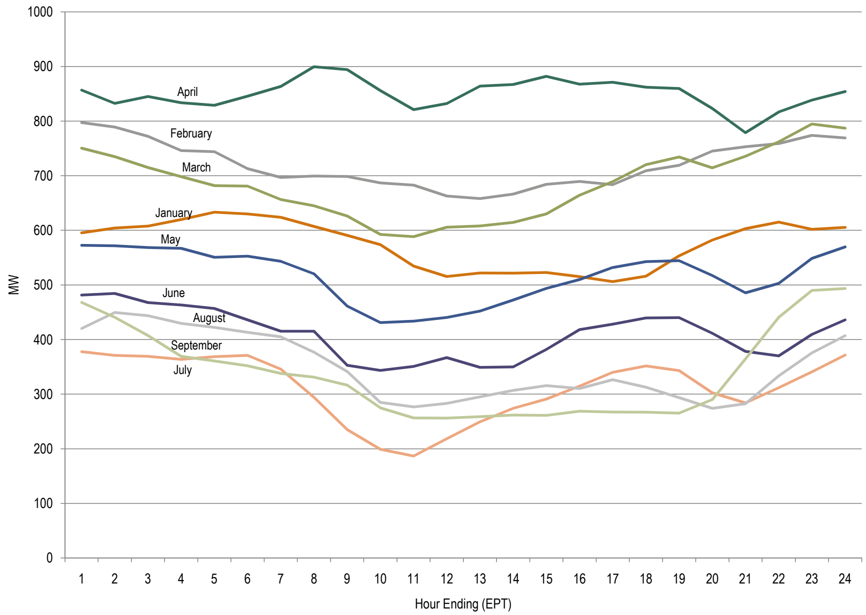


Figure 3-5 Average hourly day-ahead generation of wind units in PJM, January through September 2009 (New Figure)

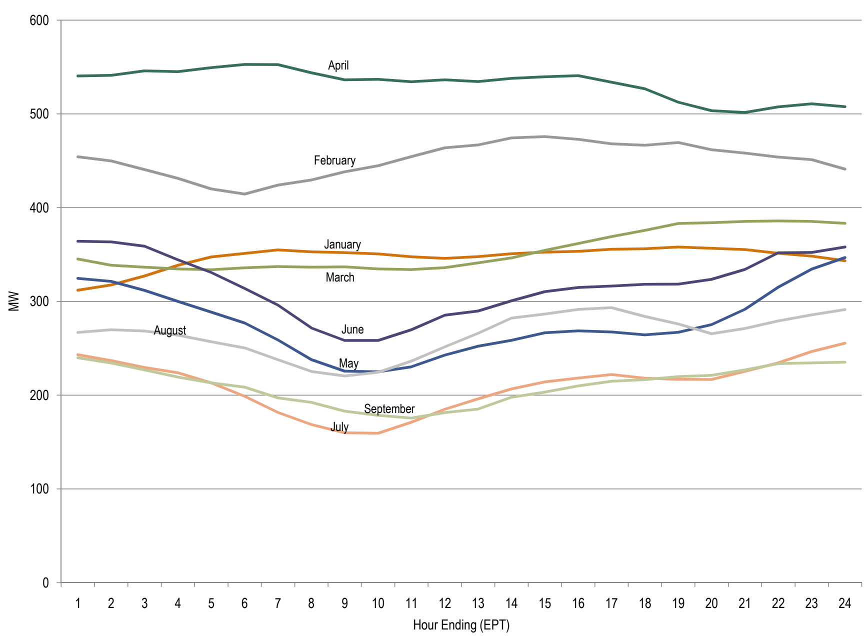
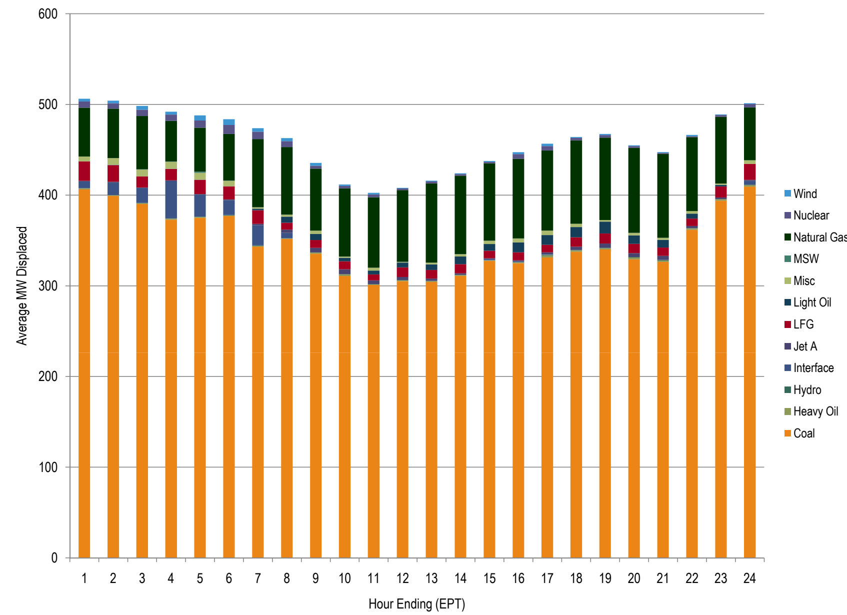


Figure 3-6 Marginal fuel displacement by wind generation in PJM, January through September 2009 (New Figure)



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Operating Reserve

Overall Results

Table 3-35 Monthly operating reserve charges: January through September 2008 and 2009[11] (See 2008 SOM, Table 3-45)

	2008 (Jan-Sep) Charges				2009 (Jan-Sep) Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$4,126,221	$456,972	$39,935,491	$44,518,684	$9,260,150	$1,328,814	$30,001,637	$40,590,601
Feb	$3,731,017	$200,456	$23,165,838	$27,097,312	$7,434,068	$839,679	$16,508,010	$24,781,756
Mar	$2,904,498	$249,900	$18,916,241	$22,070,639	$9,549,963	$108,664	$25,945,310	$35,603,936
Apr	$4,213,578	$209,366	$22,559,577	$26,982,522	$6,998,364	$19,929	$13,246,434	$20,264,727
May	$10,873,205	$202,397	$22,970,363	$34,045,964	$6,024,108	$5,543	$15,476,784	$21,506,435
Jun	$7,064,877	$575,927	$65,597,311	$73,238,115	$6,722,329	$0	$19,224,687	$25,947,016
Jul	$7,038,834	$874,234	$48,041,415	$55,954,483	$8,210,636	$38,643	$17,312,974	$25,562,253
Aug	$6,140,554	$143,857	$26,212,547	$32,496,959	$7,697,174	$1	$20,711,506	$28,408,680
Sep	$4,581,147	$405,308	$27,809,898	$32,796,353	$6,057,598	$13,611	$13,450,468	$19,521,678
Total	$50,673,931	$3,318,419	$295,208,680	$349,201,030	$67,954,390	$2,354,884	$171,877,810	$242,187,084
Share of Annual Charges	14.5%	1.0%	84.5%	100.0%	28.1%	1.0%	71.0%	100.0%

Table 3-36 Regional balancing charges allocation: January through September 2008 and 2009[12] (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$3,432,227	$134,849	$3,567,076	$49,355,811	$28,883,393	$14,803,890	$93,043,094	$96,610,170
RTO	2.6%	0.1%	2.7%	37.9%	22.2%	11.4%	71.5%	74.2%
East	$393,809	$13,683	$407,492	$5,824,239	$3,067,879	$1,559,973	$10,452,090	$10,859,583
East	0.3%	0.0%	0.3%	4.5%	2.4%	1.2%	8.0%	8.3%
West	$18,628,965	$829,980	$19,458,945	$1,640,297	$1,080,901	$560,559	$3,281,757	$22,740,702
West	14.3%	0.6%	14.9%	1.3%	0.8%	0.4%	2.5%	17.5%
Total	$22,455,001	$978,512	$23,433,513	$56,820,347	$33,032,173	$16,924,422	$106,776,941	$130,210,454
Total	17.2%	0.8%	18.0%	43.6%	25.4%	13.0%	82.0%	100.0%

11 The balancing charges shown in Table 3-35 are higher than total credits for the months of January through September, 2009 due to credits to units that were overstated in initial market settlements, and required manual refunds to the transmission owner. These make whole payments will be allocated as generator local charge credits.

12 The total charges shown in Table 3-36 do not equal the total balancing charges shown in Table 3-35 because the totals in Table 3-35 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-36 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while LOC, cancellation, and local charges are allocated on an RTO wide basis, based on demand, supply, and generator deviations.

Deviations

Table 3-37 Monthly balancing operating reserve deviations (MWh): January through September 2008 and 2009 (See 2008 SOM, Table 3-46)

	2008 (Jan-Sep) Deviations				2009 (Jan-Sep) Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	8,172,164	3,297,121	2,572,113	14,041,398	9,128,112	5,575,170	2,637,718	17,341,000
Feb	6,728,062	3,046,290	2,546,510	12,320,861	7,044,702	4,153,575	2,107,229	13,305,505
Mar	6,392,821	2,520,387	2,405,061	11,318,269	7,214,090	4,352,550	2,410,544	13,977,183
Apr	5,951,654	3,127,726	2,224,157	11,303,537	6,873,427	3,836,896	2,275,153	12,985,477
May	6,624,696	3,787,650	2,699,616	13,111,962	6,958,699	5,184,983	2,382,351	14,526,033
Jun	8,117,669	3,179,999	2,644,016	13,941,684	8,569,879	4,603,052	2,635,991	15,808,922
Jul	9,237,956	3,914,230	2,213,828	15,366,014	9,233,511	5,129,409	2,280,626	16,643,546
Aug	8,296,485	4,000,974	2,275,294	14,572,753	9,961,944	5,425,344	2,349,290	17,736,578
Sep	7,360,536	3,691,646	2,577,095	13,629,277	7,972,378	4,171,876	2,114,798	14,259,052
Total	41,987,065	18,959,174	15,091,472	76,037,711	72,956,743	42,432,853	21,193,699	136,583,296
Share of Annual Deviations	55.2%	24.9%	19.8%	100.0%	53.4%	31.1%	15.5%	100.0%

Table 3-38 Regional charges determinants (MWh): January through September 2009 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total	Total
RTO	504,137,618	20,197,925	524,335,544	72,956,743	42,432,853	21,193,699	136,583,296	660,918,840
East	278,168,510	10,073,712	288,242,222	44,817,337	23,209,690	11,485,907	79,512,935	367,755,157
West	225,969,108	10,124,213	236,093,321	27,929,588	19,159,306	9,707,792	56,796,686	292,890,007

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Figure 3-7 Daily RTO reliability and deviation rates: January through September 2009 (New Figure)

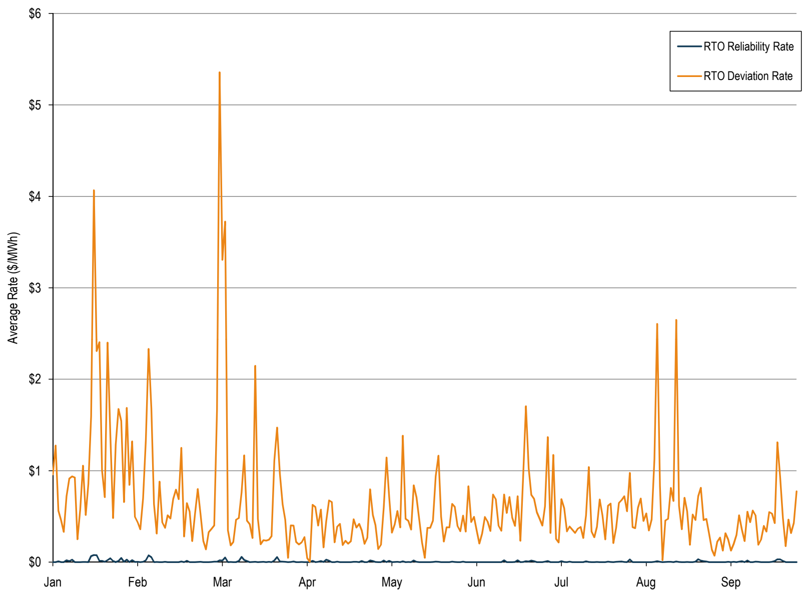
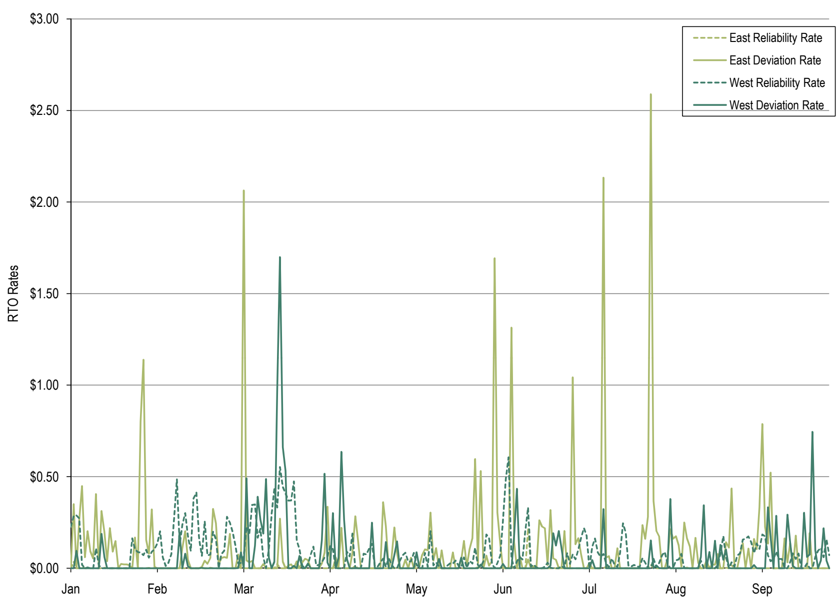


Figure 3-8 Daily regional reliability and deviation rates: January through September 2009 (New Figure)



Balancing Operating Reserve Charge Rate

Table 3-39 Average regional balancing operating reserve rates: January through September 2009 (See 2008 SOM, Table 3-48)

	Reliability	Deviations
RTO	0.006	0.648
East	0.001	0.122
West	0.087	0.057

Operating Reserve Credits by Category

Figure 3-9 Operating reserve credits: January through September 2009 (See 2008 SOM, Figure 3-11)

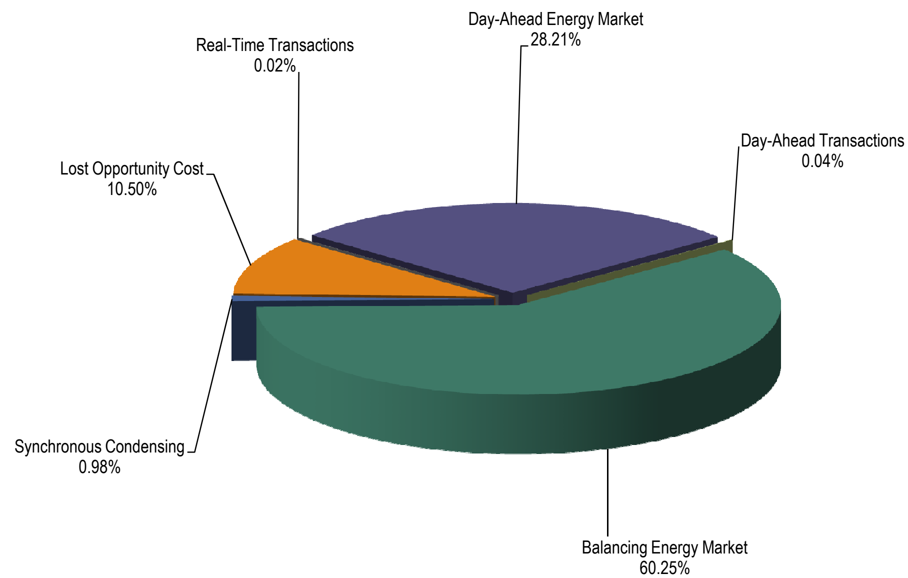


Table 3-40 Credits by month (By operating reserve market): January through September 2009 (See 2008 SOM, Table 3-49)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$9,260,150	$0	$1,328,814	$26,443,459	$0	$3,558,177	$40,590,600
Feb	$7,434,068	$0	$839,679	$14,413,879	$31,258	$2,062,873	$24,781,757
Mar	$9,542,383	$7,580	$108,664	$22,273,264	$13,249	$3,511,174	$35,456,315
Apr	$6,998,364	$0	$19,929	$10,746,431	$6,942	$1,833,546	$19,605,213
May	$6,024,108	$0	$5,543	$13,965,424	$0	$1,511,360	$21,506,435
Jun	$6,711,471	$10,858	$0	$16,058,244	$0	$2,527,907	$25,308,480
Jul	$8,183,242	$27,394	$38,643	$15,216,183	$0	$2,096,792	$25,562,254
Aug	$7,636,586	$60,588	$1	$15,210,565	$0	$5,368,663	$28,276,403
Sep	$6,057,599	$0	$13,611	$10,582,749	$0	$2,780,091	$19,434,049
Total	$67,847,971	$106,420	$2,354,884	$144,910,199	$51,449	$25,250,583	$240,521,506
Share of Credits	28.2%	0.0%	1.0%	60.2%	0.0%	10.5%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-41 Credits by unit types (By operating reserve market): January through September 2009 (See 2008 SOM, Table 3-50)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	40.1%	0.0%	59.1%	0.8%	$67,710,494
Combustion Turbine	1.6%	3.5%	72.4%	22.5%	$67,687,734
Diesel	0.1%	0.0%	4.0%	95.9%	$3,819,600
Hydro	0.0%	0.3%	99.7%	0.0%	$180,200
Nuclear	0.0%	0.0%	0.0%	100.0%	$150,645
Steam	39.3%	0.0%	55.1%	5.7%	$100,851,779
Wind Farm	0.0%	0.0%	58.4%	41.6%	$10,497

Table 3-42 Credits by operating reserve market (By unit type): January through September 2009 (See 2008 SOM, Table 3-51)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	40.0%	0.0%	27.6%	2.1%
Combustion Turbine	1.6%	100.0%	33.8%	60.2%
Diesel	0.0%	0.0%	0.1%	14.5%
Hydro	0.0%	0.0%	0.1%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.6%
Steam	58.4%	0.0%	38.3%	22.6%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$67,847,971	$2,354,884	$144,957,511	$25,250,583

Economic and Noneconomic Generation

Table 3-43 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: January through September 2009 (See 2008 SOM, Table 3-52)

	All Hours	On Peak	Off Peak
Self-scheduled generation	24.8%	23.3%	28.4%
Economic generation	63.6%	68.9%	50.7%
Noneconomic generation	10.1%	7.0%	17.7%
Regulation generation	1.5%	0.8%	3.2%
Total	100%	100%	100%

Table 3-44 PJM generation (By unit type receiving operating reserve payments): January through September 2009 (See 2008 SOM, Table 3-53)

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation
Combined cycle	3.0%	10.3%	24.4%	26.0%
Combustion turbine	0.3%	0.4%	2.1%	0.1%
Diesel	0.2%	0.0%	0.0%	0.0%
Hydroelectric	2.6%	0.6%	0.0%	0.0%
Steam	93.0%	88.7%	73.5%	74.0%
Wind	1.0%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%

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Table 3-45 PJM unit type generation distribution (By unit type receiving operating reserve payments): January through September 2009 (See 2008 SOM, Table 3-54)

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation	Total
Combined cycle	7.3%	64.6%	24.3%	3.8%	100%
Combustion turbine	12.4%	46.0%	41.5%	0.1%	100%
Diesel	75.8%	17.5%	6.7%	0.0%	100%
Hydroelectric	63.7%	36.3%	0.0%	0.0%	100%
Steam	26.1%	64.1%	8.5%	1.3%	100%
Wind	99.2%	0.8%	0.0%	0.0%	100%

Geography of Balancing Credits and Charges

Table 3-46 Monthly balancing operating reserve charges and credits to generators (By location): January through September 2009 (See 2008 SOM, Table 3-55)

	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 Deviation Credits Percent of Total Operating Reserve Credits
Jan	$2,038,901	$302,581	$2,341,482	$21,038,966	$2,617,930	$23,656,896	$1,655,607	$276,275	$1,931,882	$5,404,493	$940,247	$6,344,741	10.5%	66.6%
Feb	$799,666	$162,819	$962,486	$7,821,619	$1,685,163	$9,506,782	$726,523	$168,720	$895,243	$6,592,259	$377,710	$6,969,970	7.5%	59.5%
Mar	$1,493,041	$339,407	$1,832,448	$13,177,635	$2,283,617	$15,461,251	$1,359,326	$283,325	$1,642,651	$9,095,630	$1,227,558	$10,323,188	9.8%	64.6%
Apr	$505,788	$160,034	$665,822	$3,987,806	$1,098,113	$5,085,919	$530,487	$161,839	$692,326	$6,758,625	$735,433	$7,494,058	6.7%	56.5%
May	$701,590	$115,219	$816,808	$6,817,008	$1,311,304	$8,128,312	$700,361	$131,955	$832,316	$7,154,625	$200,056	$7,354,681	7.7%	66.1%
Jun	$1,040,688	$206,804	$1,247,492	$8,683,676	$2,014,143	$10,697,819	$920,214	$222,661	$1,142,875	$7,386,679	$513,764	$7,900,443	9.2%	65.2%
Jul	$947,502	$162,282	$1,109,784	$9,640,563	$1,855,776	$11,496,339	$617,861	$130,886	$748,748	$5,604,614	$241,016	$5,845,629	7.3%	60.8%
Aug	$1,095,199	$418,288	$1,513,487	$10,708,827	$4,839,160	$15,547,988	$838,707	$349,336	$1,188,044	$4,501,738	$529,502	$5,031,240	9.5%	56.5%
Sep	$592,176	$212,843	$805,019	$5,573,582	$2,594,659	$8,168,241	$549,716	$184,433	$734,149	$5,009,167	$185,432	$5,194,599	7.9%	56.5%
Average	52.8%	50.8%	52.4%	59.2%	73.4%	61.0%	47.2%	49.2%	47.6%	40.8%	26.6%	39.0%	8.6%	63.1%

Market Power Issues

Top 10 Units

Table 3-47 Top 10 units and organizations receiving total operating reserve credits: January through September 2009 (See 2008 SOM, Table 3-57)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$24,528,324	10.2%	10.2%	$70,296,769	29.2%	29.2%
2	$17,238,165	7.2%	17.4%	$48,586,092	20.2%	49.4%
3	$10,021,474	4.2%	21.5%	$24,600,093	10.2%	59.7%
4	$8,495,009	3.5%	25.1%	$15,209,491	6.3%	66.0%
5	$6,847,966	2.8%	27.9%	$13,079,299	5.4%	71.4%
6	$5,983,837	2.5%	30.4%	$10,049,183	4.2%	75.6%
7	$3,423,767	1.4%	31.8%	$8,715,685	3.6%	79.3%
8	$3,362,806	1.4%	33.2%	$5,556,467	2.3%	81.6%
9	$3,360,659	1.4%	34.6%	$4,086,988	1.7%	83.3%
10	$2,855,522	1.2%	35.8%	$3,729,968	1.6%	84.8%

Table 3-48 Top 10 units and organizations receiving day-ahead generator credits: January through September 2009 (See 2008 SOM, Table 3-58)

	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	$12,814,488	18.9%	18.9%	$31,542,915	46.5%	46.5%
2	$8,629,554	12.7%	31.6%	$7,800,491	11.5%	58.0%
3	$8,168,880	12.0%	43.6%	$6,372,426	9.4%	67.4%
4	$2,485,187	3.7%	47.3%	$3,940,777	5.8%	73.2%
5	$1,417,222	2.1%	49.4%	$2,662,573	3.9%	77.1%
6	$1,381,387	2.0%	51.4%	$2,267,207	3.3%	80.5%
7	$1,235,554	1.8%	53.3%	$2,010,611	3.0%	83.4%
8	$1,070,665	1.6%	54.8%	$1,861,146	2.7%	86.2%
9	$722,248	1.1%	55.9%	$1,653,297	2.4%	88.6%
10	$668,548	1.0%	56.9%	$1,622,710	2.4%	91.0%

Table 3-49 Top 10 units and organizations receiving synchronous condensing credits: January through September 2009 (See 2008 SOM, Table 3-59)

	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	$199,676	8.5%	8.5%	$2,094,463	88.9%	88.9%
2	$199,001	8.5%	16.9%	$174,494	7.4%	96.4%
3	$192,296	8.2%	25.1%	$75,847	3.2%	99.6%
4	$191,155	8.1%	33.2%	$5,133	0.2%	99.8%
5	$188,686	8.0%	41.2%			
6	$187,366	8.0%	49.2%			
7	$183,946	7.8%	57.0%			
8	$89,051	3.8%	60.8%			
9	$86,246	3.7%	64.4%			
10	$77,903	3.3%	67.7%			

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Table 3-50 Top 10 units and organizations receiving balancing generator credits: January through September 2009 (See 2008 SOM, Table 3-60)

	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	$15,896,419	11.0%	11.0%	$39,669,400	27.4%	27.4%
2	$8,148,763	5.6%	16.6%	$36,462,047	25.2%	52.5%
3	$6,277,324	4.3%	20.9%	$15,592,123	10.8%	63.3%
4	$5,570,753	3.8%	24.8%	$13,002,646	9.0%	72.2%
5	$4,314,924	3.0%	27.7%	$6,448,995	4.4%	76.7%
6	$3,080,612	2.1%	29.9%	$4,774,820	3.3%	80.0%
7	$3,019,261	2.1%	31.9%	$3,616,669	2.5%	82.5%
8	$2,450,815	1.7%	33.6%	$2,579,346	1.8%	84.3%
9	$2,187,103	1.5%	35.1%	$2,354,713	1.6%	85.9%
10	$2,087,549	1.4%	36.6%	$1,948,344	1.3%	87.2%

Table 3-51 Top 10 units and organizations receiving lost opportunity cost credits: January through September 2009 (See 2008 SOM, Table 3-61)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$1,609,528	6.4%	6.4%	$10,044,590	39.8%	39.8%
2	$1,430,884	5.7%	12.0%	$6,344,879	25.1%	64.9%
3	$1,397,091	5.5%	17.6%	$1,252,960	5.0%	69.9%
4	$1,308,823	5.2%	22.8%	$1,116,201	4.4%	74.3%
5	$1,292,277	5.1%	27.9%	$1,060,867	4.2%	78.5%
6	$1,257,205	5.0%	32.9%	$1,047,433	4.1%	82.6%
7	$1,047,433	4.1%	37.0%	$909,480	3.6%	86.2%
8	$909,480	3.6%	40.6%	$493,238	2.0%	88.2%
9	$843,495	3.3%	43.9%	$462,045	1.8%	90.0%
10	$680,646	2.7%	46.6%	$317,087	1.3%	91.3%

Figure 3-10 Cumulative distribution of units receiving credits (By operating reserve category): January through September 2009 (See 2008 SOM, Figure 3-12)

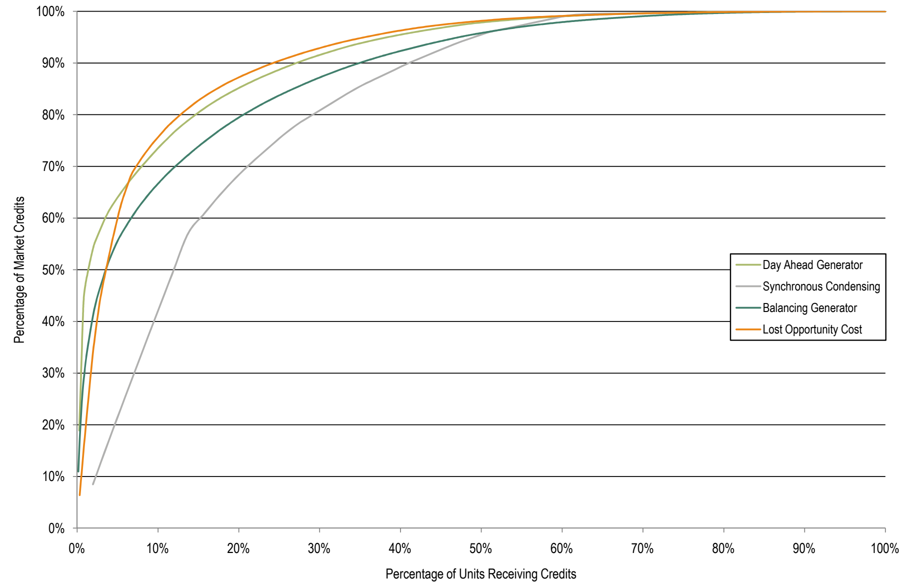
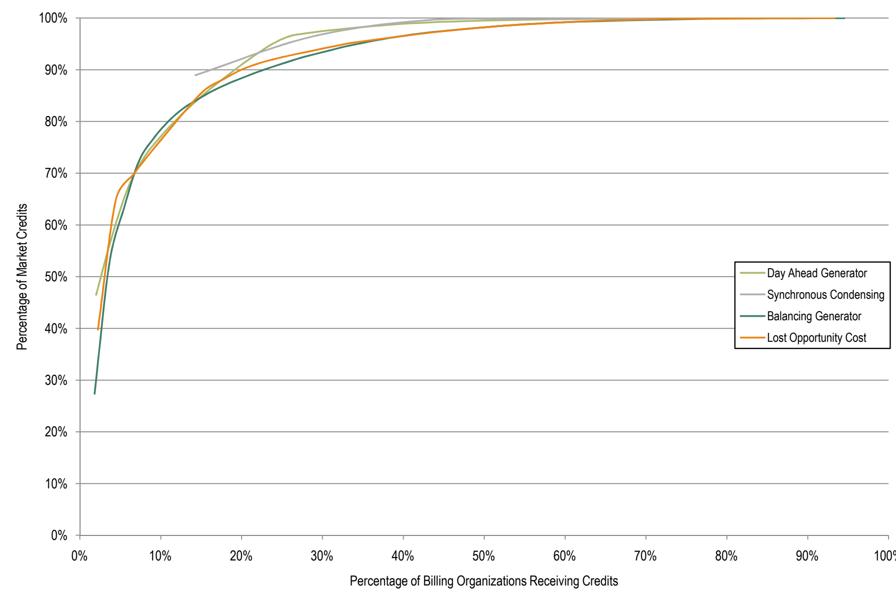


Figure 3-11 Cumulative distribution of billing organizations receiving credits (By operating reserve market): January through September 2009 (See 2008 SOM, Figure 3-13)



Markup

Unit Markup - Top 10 Units

Table 3-52 Top 10 operating reserve revenue units markup: January through September 2009 (See 2008 SOM, Table 3-62)

	Top 10 Units Weighted Markup	Steam Share of Top 10 Units Credits	Steam Units in Top 10 Weighted Markup	Combined Cycle Share of Top 10 Units Credits	Combined Cycle Units in Top 10 Weighted Markup	Combustion Turbine Share of Top 10 Units Credits	Combustion Turbine Units in Top 10 Weighted Markup
2009 (Jan -Sep)	(1.2%)	47.6%	(9.4%)	52.4%	3.5%	0.0%	NA

Unit Markup - All Units

Table 3-53 Average real-time weighted markup by unit type receiving balancing credits: January through September 2009 (New Table)

Unit Type	Number of Units	Weighted Markup
Combustion Turbine	391	(17.0%)
Steam	241	(7.8%)
Combined Cycle	48	(8.8%)
Diesel	21	(63.8%)
Hydro	11	259.2%
Nuclear	2	(30.0%)
Wind Farm	2	0.0%

Review of Impact on Regional Balancing Operating Reserve Charges

Total regional balancing generator credits for both reliability and deviation purposes for January through September 2009 totaled $130,210,454.

Table 3-54 Regional balancing operating reserve credits: January through September 2009 (New Table)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$3,567,076	$93,043,094	$96,610,170
East	$407,492	$10,452,090	$10,859,583
West	$19,458,945	$3,281,757	$22,740,702
Total	$23,433,513	$106,776,941	$130,210,454

Table 3-55 Total deviations: January through September 2009 (New Table)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	72,956,743	42,432,853	21,193,699	136,583,296

Under the old operating reserve construct, total credits for the day would have been allocated to demand, supply, and generator deviations at the rate of credits/deviations. This balancing rate would then have been applied against each organizations demand, supply, and generator deviations in the form of charges.

Table 3-56 Charge allocation under old operating reserve construct: January through September 2009 (New Table)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	72,956,743	42,432,853	21,193,699	136,583,296
Balancing Rate ($/MWh)	0.953	0.953	0.953	0.953
Charges ($)	$69,552,654	$40,452,978	$20,204,822	$130,210,454

Under the new operating reserve construct, rates are applied separately to credits for reliability or deviation purposes in the Eastern, Western, and RTO regions, resulting in six balancing rates. Reliability credits are allocated by Real-Time load MWh plus Real-Time export MWh in the Eastern and Western regions, and the sum of those MWh for the RTO rate. Regional deviation credits are allocated to the sum of demand, supply, and generator deviations for each region in which they occur (deviations at aggregates that span both regions apply to RTO deviations). Total RTO deviations are the sum of the Eastern deviations, Western deviations, and the deviations that were directly applied to the RTO.

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For January through September 2009, charges were actually allocated as shown in Table 3-57.

The difference between the charges based on the old operating reserve construct (see Table 3-56) and the actual charges allocated under the current rules is shown in Table 3-58, separated by deviation type. The total amount of charges reallocated from the demand, supply, and generator deviations is equal to the amount of total reliability charges.

A breakdown of the reallocation of charges for the period January through September 2009 is shown in Table 3-59.

Table 3-57 Actual regional credits, charges, rates and charge allocation MWh: January through September 2009 (New Table)

	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	$3,567,076	524,335,544	0.007	$3,567,076	$93,043,094	136,583,296	0.681	$93,043,094	$96,610,170
East	$407,492	288,242,222	0.001	$407,492	$10,452,090	79,512,935	0.131	$10,452,090	$10,859,583
West	$19,458,945	236,093,321	0.082	$19,458,945	$3,281,757	56,796,686	0.058	$3,281,757	$22,740,702
Total	$23,433,513	524,335,544	NA	$23,433,513	$106,776,941	136,583,296	NA	$106,776,941	$130,210,454

Table 3-58 Difference in total charges between old rules and new rules: January through September 2009 (New Table)

	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	$69,552,654	$40,452,978	$20,204,822	$130,210,454
Charges (Current)	$22,455,001	$978,512	$23,433,513	$56,820,347	$33,032,173	$16,924,422	$106,776,941
Difference	$22,455,001	$978,512	$23,433,513	($12,732,306)	($7,420,806)	($3,280,401)	($23,433,513)

Table 3-59 Difference in total charges between old rules and new rules: January through September 2009 (New Table)

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Difference	$22,455,001	$978,512	$23,433,513	($12,732,306)	($7,420,806)	($3,280,401)	($23,433,513)

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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.** PJM was a monthly net exporter of energy during the period from 2004 through late 2008. PJM was a monthly net importer of energy in the Real-Time Market in January, February, March and May of 2009, and a net exporter of energy in April, June, July, August and September. In the Real-Time Market, monthly net interchange averaged -20 GWh.[1] Gross monthly import volumes averaged 3,738 GWh while gross monthly exports averaged 3,758 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market.** PJM was a net exporter of energy in the Day-Ahead Market in all months except July. The Day-Ahead monthly net interchange averaged -665 GWh. Gross monthly import volumes averaged 4,106 GWh while gross monthly exports averaged 4,771 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** During the first nine months of 2009, gross imports in the Day-Ahead Energy Market were 110 percent of the Real-Time Market's gross imports (90 percent for the calendar year 2008) while gross exports in the Day-Ahead Market were 127 percent of the Real-Time Market's gross exports (106 percent for the calendar year 2008).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market, during the first nine months of 2009, there were net exports at 12 of PJM's 21 interfaces.[2] The top four net exporting interfaces in the Real-Time Market accounted for 72 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 50 percent (PJM/Neptune (NEPT) with 27 percent and PJM/NYIS with 23 percent), PJM/Carolina Power and Light-East (CPLE) with 13 percent and PJM/First Energy (FE) with 9 percent of the net export volume. Nine PJM interfaces had net imports, with two importing interfaces accounting for 88 percent of the net import volume: PJM/Ohio Valley Electric Corporation (OVEC) with 66 percent and PJM/Michigan Electric Coordinated System (MECS) with 22 percent.

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, there were net exports at 13 of PJM's 21 interfaces. The top three net exporting interfaces accounted for 62 percent of the total net exports, PJM/western Alliant Energy Corporation (ALTW) with 24 percent, PJM/eastern Alliant Energy Corporation (ALTE) with 19 percent and PJM/NYIS with 17 percent. (While there were net imports at the PJM/NYIS interface in the Day-Ahead, when combined with the net exports at the PJM/NEPTUNE (NEPT) interface, the overall interchange with the NYISO accounts for 17 percent of the Day-Ahead exports). There were net imports in the Day-Ahead Market at eight of PJM's 21 interfaces. The top three importing interfaces accounted for 80 percent of the total net imports, PJM/OVEC with 51 percent, PJM/Michigan Electric Coordinated System (MECS) with 18 percent and PJM/Wisconsin Energy Corporation (WEC) with 11 percent.

- **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, including undersea and underground cable, was placed in service. This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bidirectional, but in the first nine months of 2009, power flows were only from PJM to New York. The average hourly flow during the first nine months of 2009 was -567 MW.

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 September 2009, the Linden Variable Frequency Transformer (VFT) facility began testing. This facility is treated as a separate interface with PJM, bringing the total interfaces with PJM to 21.

- **Linden Variable Frequency Transformer (VFT) facility.** On November 1, 2009, the Linden VFT facility is expected to be placed in service, providing an additional connection between PJM and the New York Independent System Operator, Inc. A variable frequency transformer is a technology which allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle regulating transformer. 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.[3] In September 2009, PJM and the NYISO began scheduling flow across this line for the purposes of testing. The average hourly flow during the initial testing period in September 2009 was -24 MW.

Interactions with Bordering Areas

- **PJM Interface Pricing with Organized Markets.**
  - **PJM and Midwest ISO Interface Pricing.** During the first nine months of 2009, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals, as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.
  - **PJM and New York ISO Interface Pricing.** During the first nine months of 2009, 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 NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and NYISO.
  - **PJM TLRs.** During the first nine months of 2009, PJM issued 116 transmission loading relief procedures (TLRs). Of the 116 TLRs issued, the highest levels reached were TLR 3a in 57 instances and TLR 3b in the remaining 59 events. This represents a decrease of 9 percent in TLRs from the 127 TLRs issued during the first nine months of 2008. (47 TLR 3a, 77 TLR 3b, 2 TLR 4 and 1 TLR 5b).

- **Operating Agreements with Bordering Areas.**
  - **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[4] On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering. While the JOA does not include provisions for market-based congestion management or other market-to-market activity, at the request of PJM, PJM and the NYISO began discussion of a market-based congestion management protocol.
  - **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 2009. The market-based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[5]

    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.[6]

3 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed November 4, 2009) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,403 KB).

4 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed November 4, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

5 See PJM. "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (November 1, 2007) (Accessed November 4, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,534 KB).

6 See PJM. "PJM/MISO Market Flow Calculation Error" (September 10, 2009) (Accessed October 14, 2009) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

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As of October 1, 2009, PJM and the Midwest ISO had not agreed upon a method to estimate the amount for the entire period. Differences have also emerged over how the parties are administering the Joint Operating Agreement, such as the use by Midwest ISO of proxy flowgates. This practice, if confirmed, measured and determined inconsistent with the Joint Operating Agreement, would mean that the Midwest ISO received more compensation than appropriate. The parties are currently engaged in a confidential FERC mediated settlement process.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[7] 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 2009.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[8] On September 9, 2005, the United States Federal Energy Regulatory Commission (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 2009. As part of this agreement, both parties agreed to develop a formal CMP. During the first nine months of 2009, PEC and PJM continued confidential discussions on more granular interface pricing as well as the development of the CMP.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[9] On May 23, 2007, PJM and VACAR South (VACAR is a subregion 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.

- **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 2009, PJM continued to operate under the terms of the operating protocol developed in 2005.[10]

Interchange Transaction Issues

- **Up-To Congestion.** In 2008, market participants requested that PJM increase the maximum value for up-to congestion offers, and to also allow negative offers for these transactions. PJM expressed concerns regarding the mismatch between up-to congestion transactions in the Day-Ahead Market and real-time transactions.[11] In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity. Increasing the offer cap, and allowing negative offers, could increase the cleared volume of up-to congestion transactions, and aggravate the issue.

  On February 21, 2008, the MRC approved PJM's proposed resolution to the request for implementation on March 1, 2008.[12] The proposal allowed for an increased offer cap from \$25 to ± \$50, and explicitly allowed for negative offers. PJM also eliminated certain available sources and sinks in an effort to partially address the mismatch between the Day-Ahead and Real-Time Markets.

  The MMU recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

- **Loop Flows.** Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths

7 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed November 4, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

8 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed November 4, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2.98 MB).

9 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed November 4, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

10 111 FERC ¶ 61,228 (2005).

11 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed November 4, 2009) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221-item-03-up-to-congestion-transactions.ashx> (38KB).

12 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed November 4, 2009) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mrc/20080221-minutes.ashx > (61KB).

that the energy takes. Although PJM's total scheduled and actual flows differed by 5 percent in the first nine months of 2009, greater differences existed at individual interfaces. 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 2008, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-10,536 GWh during the first nine months of 2009 and -14,014 GWh during the calendar year 2008), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (2,614 GWh during the first nine months of 2009 and 4,065 GWh during the calendar year 2008). The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

- **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 2009.

- **Loop Flows at PJM's Northern Interfaces.** In 2008, new loop flows were created when pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows.[13] PJM's interface pricing calculations correctly reflected the actual power flows, but NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

13 See the *2008 State of the Market Report for PJM*, Volume II, "Interchange Transactions."

During the third quarter of 2009, the Broader Regional Markets group, consisting of representatives from PJM, NYISO, MISO and IESO, continued to work on a solution to the northeastern loop flow issues. The group developed several recommendations, including the use of Phase Angle Regulators (PARs) to control energy flows, a buy-through congestion methodology and the development of new technology to visualize the loop flows.

The use of PARs to regulate power flows is an engineering solution that can be used to directly affect power flows but the increased use of PARs does not address the underlying market pricing issues which provide an incentive for loop flows and is unlikely to provide a solution to loop flows.

Implementing a buy-through congestion methodology is also unlikely to resolve the underlying pricing issue. PJM offers a similar product, where market participants will be allowed to continue to flow their transactions when they would otherwise be curtailed by a TLR, if they were willing to pay the congestion costs of their parallel flows affecting the PJM system. This product, called "TLR Buy-Through", was implemented in PJM in 2001. In the nearly eight years that PJM has offered this product, it has never been used by market participants. Instead, the transactions were curtailed in the TLR process to alleviate the loop flows. The buy-through congestion methodology also included a recommendation that the NYISO move to a less than hourly dispatch timeframe. This is a positive step as using dispatch on the quarter hour, the NYISO market participants will be able to respond more quickly to NYISO pricing signals.

The development of a visualization tool to help identify loop flows could provide useful information to dispatch personnel, but does not address the underlying pricing problem.

The MMU recommends that a change in the interface pricing methodology be addressed directly. The MMU recommends that the parties consider the uniform adoption of a Generation Control Area (GCA) to Load Control Area (LCA) pricing methodology, similar to that used by PJM, to set transaction prices based on the actual flow of energy from source to sink. With the appropriate pricing, the incentive for market participants to schedule around specific RTOs/ISOs would be eliminated.

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- **Data Required for Full Loop Flow Analysis.** A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The term non market area is a misnomer in the sense that all electricity transactions are part of the broad energy market in the Eastern Interconnection. There are areas with transparent markets, and there are areas with less transparent markets, but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flow.

  The MMU recommends that PJM and the Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would contribute to the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impact data, actual flowgate flow data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

Additional Interchange Transaction Analysis

- **Interface Pricing Agreements with Individual Companies.** PJM entered into confidential locational interface pricing agreements with Duke Energy Carolinas, Progress Energy Carolinas and North Carolina Municipal Power Agency (NCMPA) in 2007 that provided more advantageous pricing to these companies than the applicable interface pricing rules. Each of these agreements established a locational price for purchases and sales between PJM and the individual company that applied under specified conditions. There were a number of issues with these agreements including that they were not made public until specifically requested by the MMU, that the pricing was not available to other participants in similar circumstances, that the pricing was not designed to reflect actual power flows, that the pricing did not reflect full security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate and in 2008 provided the required notification to terminate the agreements. The agreements were terminated on February 1, 2009.

  In addition to terminating the agreements, PJM worked through the stakeholder process to develop a revision to the tariff that would enhance the method for calculating interface pricing with all neighboring balancing authorities that wish to take advantage of the more granular interface pricing. The new interface pricing methodology includes three options.

  The proposed tariff revisions were filed with FERC on December 2, 2008[14], and approved on May 1, 2009.[15] As a condition of the approval, the Commission required that PJM establish procedures to negotiate, in good faith, a congestion management agreement (which is necessary for eligibility to continue the “high/low” and “marginal cost proxy” pricing beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[16] As of October 1, 2009, each of Duke Energy Carolinas, Progress Energy Carolinas and the North Carolina Municipal Power Agency was in the process of negotiating a congestion management agreement with PJM.

  As of July 2009, Duke Energy Carolinas had submitted the required data, and PJM had completed the required software modifications to support the “marginal cost proxy method.” As of October 1, 2009, neither Progress Energy Carolinas nor the North Carolina Municipal Power Agency has elected to supply the additional data necessary to take advantage of the “high/low” or the “marginal cost proxy method” for interface pricing. Figure 4-18 through Figure 4-21 show the real-time and day-ahead prices for imports and exports applicable for the interface pricing under the various agreements. During the period from February 1 through May 3, 2009, the interface pricing is based on the SouthIMP and SouthEXP LMPs as there were no agreements in place.

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion (WPC), including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its Joint Operating Agreement (JOA) with Midwest ISO to require a limitation on cross-border transmission service and energy schedules in order to limit

14 PJM Interconnection, L.L.C., Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008).
15 PJM Interconnection, L.L.C., Letter Order, Docket No. ER09-369-000 (May 1, 2009).
16 127 FERC ¶ 61,101.

the impact of such transactions on selected external flowgates.[17] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result of the rule, requests for service sometimes exceeded the amount of service available to customers. Unlike non-firm point-to-point WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

The new spot import rules provided incentives to hoard spot import capability. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the reservations queued time intraday, and at 5:00 EPT when queued the day prior. On June 23, PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage has been over 99 percent, compared to 70 percent prior to the modification. (See Figure 4-22). The MMU will continue to monitor participant use of spot import service.

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 neighboring balancing authorities for the first nine months of 2009, including evolving transaction patterns, economics and issues. During the first nine months of 2009, PJM was a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Four interfaces accounted for 72 percent of the total real-time net exports and two interfaces accounted for 88 percent of the real-time net import volume. Three interfaces accounted for 62 percent of the total day-ahead net exports and three interfaces accounted for 80 percent of the day-ahead net import volume.

In order to manage interactions with other market areas, PJM has entered into formal agreements with a number of balancing authorities. The redispatch agreement between PJM and the Midwest ISO is a model for such agreements and is being continuously improved. As interactions with external areas are increasingly governed by economic fundamentals, interface prices and volumes reflect supply and demand conditions. However, more needs to be done to assure that market signals are used to manage constraints affecting interarea transactions. PJM and NYISO, as neighboring market areas, should develop market-based congestion management protocols as soon as practicable. In addition, PJM should continue its efforts to gain access to the data required to understand loop flows in real-time and to ensure that responsible parties pay their appropriate share of the costs of redispatch.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other balancing authorities as a first step. In addition, PJM has attempted to address loop flows by creating and modifying interface prices that reflect actual power flows, regardless of contract path. Loop flows are also managed through the use of redispatch and TLR procedures. PJM has entered into dynamic scheduling agreements with generation owners for specific units to permit transparent, market-based signals and responses. PJM has modified the rules governing the use of limited transaction ramp capability between PJM and contiguous balancing authorities to help ensure that transactions are free to respond to market signals and to reduce the ability to game or hoard ramp. PJM also entered into agreements with specific balancing authorities for separate interface pricing that have been questioned with respect to transparency and equal access. PJM needs to ensure that such pricing is transparent, accurately reflects actual LMP impacts on PJM, and that all participants have access to the defined pricing when in the same position. The goal of such pricing agreements should be to replicate LMP price signals that reflect the actual loads and the actual dispatch of units.

Loop flows are measured as the difference between actual and scheduled (contract path) flows at one or more specific interfaces. Loop flows do

17 See "WPC White Paper" (April 20, 2007) (Accessed November 4, 2009) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

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not exist within markets because power flows are explicitly priced under locational marginal pricing, but markets can create loop flows in external balancing authorities. PJM attempts to manage loop flows by creating interface prices that reflect the actual power flows, regardless of contract path. But this approach cannot be completely successful as long as it is possible to schedule a transaction and be paid based on that schedule, regardless of how the power flows.

PJM continues to face significant loop flows for reasons that continue not to be fully understood as a result of inadequate access to the required data. A complete analysis of loop flow across the Eastern Interconnection could improve overall market efficiency, shed light on the interactions among market and non market areas and permit market based congestion management across the Eastern Interconnection. Loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

PJM needs to continue to pay careful attention to all the mechanisms used to manage flows at the interfaces between PJM and surrounding areas. PJM manages its interface with external areas, in part, through limitations on the amount of change in net interchange within 15-minute intervals. The change in net interchange is referred to as ramp. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. As a result of the fact that ramp is free but is a valuable resource, there are strong incentives to game the ramp rules. The same is true of spot import service. Up-to congestion service is a market option used to import power to or export power from PJM which can create mismatches between transactions in the Day-Ahead Energy Market and the Real-Time Energy Market that result in inaccurate pricing and can provide a gaming opportunity.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through September 2009 (See 2008 SOM, Figure 4-1)

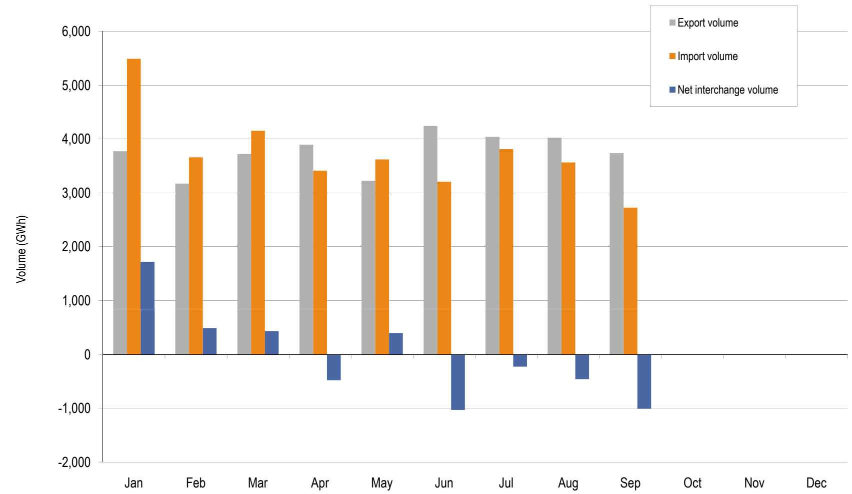


Figure 4-2 PJM day-ahead scheduled imports and exports: January through September 2009 (See 2008 SOM, Figure 4-2)

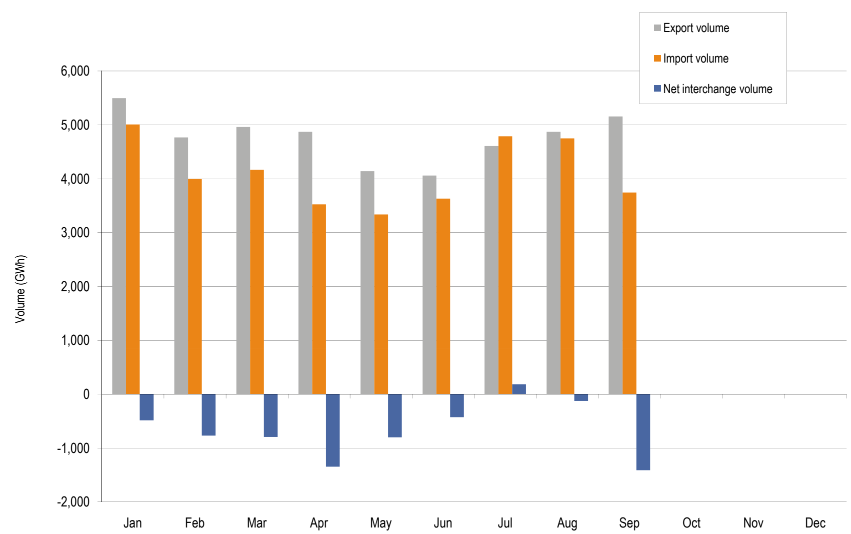
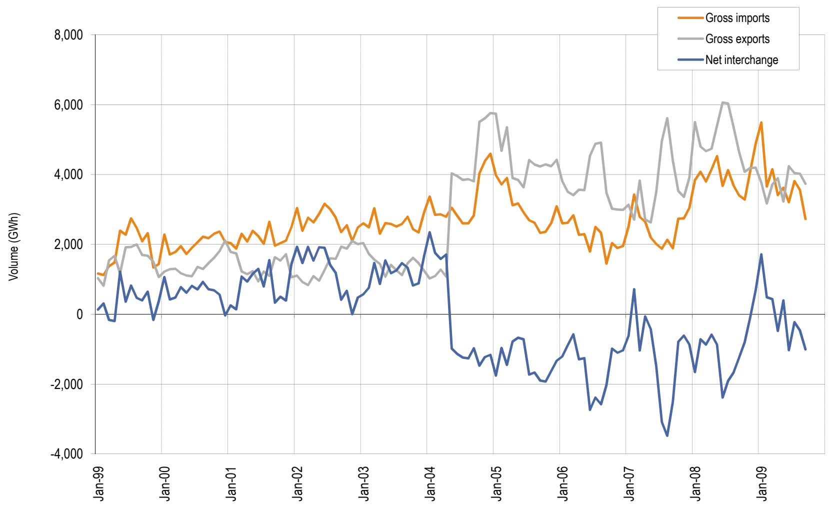


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through September 2009 (See 2008 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	44.4	(41.8)	(86.5)	(147.3)	(117.6)	(143.6)	(136.3)	(94.9)	(39.1)	(762.7)
ALTW	(65.6)	(69.6)	(74.3)	(97.5)	(66.4)	(175.3)	(230.4)	(151.1)	(92.2)	(1,022.4)
AMIL	126.2	23.7	8.7	(14.9)	28.0	(24.0)	(6.8)	(13.6)	24.6	151.9
CIN	102.6	(96.1)	(179.7)	(216.6)	14.7	(91.8)	154.0	133.9	206.5	27.5
CPLE	(62.7)	(161.8)	(208.1)	(281.1)	(113.8)	(293.2)	(317.7)	(242.9)	(241.7)	(1,923.0)
CPLW	(71.4)	(67.4)	(74.3)	(72.0)	(60.3)	(69.8)	(74.6)	(76.7)	(57.6)	(624.1)
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.7
DUK	622.7	67.8	89.9	10.6	60.9	(86.0)	(135.9)	(67.5)	(180.9)	381.6
EKPC	(173.5)	(78.8)	(88.6)	(57.4)	67.3	(9.7)	(45.0)	(57.3)	(113.1)	(556.1)
FE	(215.6)	(221.5)	(166.6)	(204.3)	(178.6)	(93.1)	(16.8)	(80.2)	(168.8)	(1,345.5)
IPL	47.1	(17.5)	(88.6)	(79.8)	101.5	(23.9)	173.4	(5.7)	(14.2)	92.3
LGEE	137.4	90.7	176.3	101.4	169.8	32.6	(3.9)	54.6	43.5	802.4
LIND									(8.9)	(8.9)
MEC	150.4	302.1	146.1	155.1	(148.4)	(239.8)	(117.9)	(26.8)	(446.6)	(225.8)
MECS	421.7	361.8	552.3	60.9	341.6	398.7	512.8	258.3	157.3	3,065.4
NEPT	(294.8)	(402.5)	(445.1)	(400.9)	(434.5)	(456.9)	(493.9)	(484.6)	(382.6)	(3,795.8)
NIPS	(8.2)	(51.5)	(35.5)	(60.0)	(3.9)	(38.1)	(13.9)	(71.5)	(28.0)	(310.6)
NYIS	(396.1)	(231.7)	(253.3)	(180.8)	(265.5)	(466.0)	(489.6)	(583.6)	(453.1)	(3,319.7)
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	1,116.3	1,125.0	865.0	9,268.3
TVA	244.0	128.7	167.6	35.2	69.3	(160.0)	(73.1)	(23.1)	(42.7)	345.9
WEC	(64.6)	(41.0)	(26.5)	(44.9)	(38.3)	(86.3)	(30.4)	(53.7)	(36.6)	(422.3)
Total	1,715.3	487.8	432.9	(481.8)	396.2	(1,031.0)	(229.7)	(461.4)	(1,009.2)	(180.9)

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Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-2)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	170.4	65.4	18.2	1.7	0.1	0.1	1.7	0.0	2.1	259.7
ALTW	45.7	22.2	1.7	0.0	1.9	3.5	5.1	0.3	4.8	85.2
AMIL	147.3	44.9	38.3	26.8	62.2	48.6	65.8	54.0	46.5	534.4
CIN	382.9	265.0	335.2	209.3	256.2	335.3	332.8	402.7	443.7	2,963.1
CPLE	223.9	69.4	66.8	39.9	115.1	16.8	9.3	17.0	5.2	563.4
CPLW	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.7
DUK	737.8	277.9	209.5	154.1	239.2	151.2	101.4	98.5	72.6	2,042.2
EKPC	2.7	6.1	12.9	2.5	90.3	33.2	11.6	4.2	0.9	164.4
FE	60.5	32.6	101.6	60.8	73.0	160.0	251.7	180.8	130.3	1,051.3
IPL	107.5	43.8	51.9	63.5	148.6	65.7	199.1	52.0	33.0	765.1
LGEE	187.4	125.2	183.6	125.8	172.0	55.7	48.0	72.1	44.3	1,014.1
LIND									0.0	0.0
MEC	337.6	428.2	371.7	361.2	77.8	26.5	113.5	182.9	4.8	1,904.2
MECS	573.5	500.4	679.7	264.3	458.0	486.8	601.6	368.9	246.7	4,179.9
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	32.5	8.1	0.5	0.0	11.0	0.0	18.2	0.0	0.0	70.3
NYIS	1,004.4	589.8	829.7	982.3	795.2	791.0	862.5	915.8	738.0	7,508.7
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	1,116.3	1,125.0	865.0	9,268.3
TVA	292.8	185.1	214.2	107.1	146.2	31.4	65.9	88.9	86.0	1,217.6
WEC	8.7	1.2	17.8	0.6	4.4	5.8	6.9	0.1	2.5	48.0
Total	5,489.0	3,659.5	4,152.4	3,412.4	3,621.6	3,206.8	3,811.4	3,563.2	2,726.4	33,642.7

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-3)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	126.0	107.2	104.7	149.0	117.7	143.7	138.0	94.9	41.2	1,022.4
ALTW	111.3	91.8	76.0	97.5	68.3	178.8	235.5	151.4	97.0	1,107.6
AMIL	21.1	21.2	29.6	41.7	34.2	72.6	72.6	67.6	21.9	382.5
CIN	280.3	361.1	514.9	425.9	241.5	427.1	178.8	268.8	237.2	2,935.6
CPLE	286.6	231.2	274.9	321.0	228.9	310.0	327.0	259.9	246.9	2,486.4
CPLW	73.5	67.4	74.3	72.0	60.3	69.8	74.6	76.7	57.6	626.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	115.1	210.1	119.6	143.5	178.3	237.2	237.3	166.0	253.5	1,660.6
EKPC	176.2	84.9	101.5	59.9	23.0	42.9	56.6	61.5	114.0	720.5
FE	276.1	254.1	268.2	265.1	251.6	253.1	268.5	261.0	299.1	2,396.8
IPL	60.4	61.3	140.5	143.3	47.1	89.6	25.7	57.7	47.2	672.8
LGEE	50.0	34.5	7.3	24.4	2.2	23.1	51.9	17.5	0.8	211.7
LIND									8.9	8.9
MEC	187.2	126.1	225.6	206.1	226.2	266.3	231.4	209.7	451.4	2,130.0
MECS	151.8	138.6	127.4	203.4	116.4	88.1	88.8	110.6	89.4	1,114.5
NEPT	294.8	402.5	445.1	400.9	434.5	456.9	493.9	484.6	382.6	3,795.8
NIPS	40.7	59.6	36.0	60.0	14.9	38.1	32.1	71.5	28.0	380.9
NYIS	1,400.5	821.5	1,083.0	1,163.1	1,060.7	1,257.0	1,352.1	1,499.4	1,191.1	10,828.4
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	48.8	56.4	46.6	71.9	76.9	191.4	139.0	112.0	128.7	871.7
WEC	73.3	42.2	44.3	45.5	42.7	92.1	37.3	53.8	39.1	470.3
Total	3,773.7	3,171.7	3,719.5	3,894.2	3,225.4	4,237.8	4,041.1	4,024.6	3,735.6	33,823.6

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	(142.2)	(61.4)	(518.5)	(673.0)	(779.1)	(521.6)	(340.1)	(409.7)	(542.5)	(3,988.1)
ALTW	(722.6)	(756.0)	(604.5)	(746.7)	(389.5)	(497.7)	(392.8)	(552.0)	(417.7)	(5,079.5)
AMIL	52.8	72.3	42.2	86.6	102.4	261.6	153.3	32.6	6.3	810.1
CIN	(225.4)	(96.3)	(47.8)	57.5	(36.7)	55.7	(8.5)	85.2	80.3	(136.0)
CPLE	49.1	(23.0)	(86.0)	(81.0)	(88.1)	(157.1)	(158.8)	(109.9)	(91.0)	(745.8)
CPLW	(176.6)	(166.0)	(184.5)	(180.0)	(155.9)	(176.2)	(184.7)	(184.0)	(147.8)	(1,555.7)
CWLP	(0.7)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.8)
DUK	255.9	26.4	1.1	22.3	120.9	58.7	88.5	45.5	(30.9)	588.5
EKPC	(31.1)	(22.8)	(1.1)	0.0	0.0	0.0	0.0	(1.4)	(0.3)	(56.7)
FE	(206.7)	(233.8)	(241.4)	(197.3)	(206.0)	(116.4)	(119.4)	(76.8)	(115.4)	(1,513.2)
IPL	(316.7)	(191.0)	(157.2)	(67.1)	85.2	143.0	254.3	165.3	(34.8)	(119.0)
LGEE	(16.5)	(8.9)	23.5	6.9	9.7	39.9	38.0	2.7	46.4	141.7
LIND									(2.7)	(2.7)
MEC	27.3	(90.0)	(173.4)	(185.3)	(209.3)	(252.9)	(216.0)	(207.8)	(448.7)	(1,756.1)
MECS	101.9	172.9	250.4	261.1	370.6	433.8	548.7	356.0	257.0	2,752.4
NEPT	(326.4)	(403.8)	(446.4)	(402.1)	(436.6)	(472.3)	(496.9)	(491.7)	(408.7)	(3,884.9)
NIPS	(233.7)	(320.9)	(71.3)	(194.6)	(286.2)	(62.2)	(81.7)	(287.8)	(591.0)	(2,129.4)
NYIS	158.7	146.5	130.8	7.5	(1.8)	(8.2)	7.9	(42.1)	(153.3)	245.9
OVEC	835.6	743.5	786.0	738.6	824.2	857.3	1,028.8	1,038.7	795.4	7,648.1
TVA	482.5	384.6	151.7	81.8	5.4	(42.8)	18.0	79.6	(22.7)	1,138.1
WEC	(52.5)	57.0	352.4	117.2	269.0	28.7	43.4	434.7	409.8	1,659.7
Total	(487.2)	(770.8)	(794.0)	(1,347.6)	(801.8)	(428.7)	182.0	(122.9)	(1,412.3)	(5,983.3)

Table 4-5 Day-ahead gross import volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-5)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	675.2	674.4	470.1	173.7	52.2	106.5	367.9	191.1	171.6	2,882.7
ALTW	190.8	183.6	33.2	2.3	0.0	12.5	29.9	40.4	15.8	508.5
AMIL	59.4	75.0	44.5	91.5	105.0	261.6	155.7	76.1	17.7	886.5
CIN	103.2	159.2	178.5	247.6	190.5	320.2	273.2	328.9	391.8	2,193.1
CPLE	187.6	75.8	14.4	21.0	24.0	7.8	7.4	19.8	12.4	370.2
CPLW	9.5	2.1	0.6	0.0	2.8	0.0	2.2	2.0	0.0	19.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	291.9	102.7	55.9	71.4	138.8	90.0	123.6	66.8	83.6	1,024.7
EKPC	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
FE	15.2	44.9	60.0	23.0	10.3	100.7	206.1	227.7	242.0	929.9
IPL	246.5	159.9	153.2	254.2	258.7	250.0	389.3	374.6	77.6	2,164.0
LGEE	2.9	0.2	24.9	8.1	11.4	41.0	40.1	5.2	46.4	180.2
LIND									0.0	0.0
MEC	173.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	174.9
MECS	504.9	400.1	488.5	606.8	631.9	626.5	769.8	595.9	390.9	5,015.3
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	284.5	248.4	490.5	208.0	135.6	151.4	338.2	231.6	152.0	2,240.2
NYIS	890.3	584.5	776.0	776.4	612.0	675.0	840.6	958.6	710.3	6,823.7
OVEC	866.7	766.6	810.5	763.1	828.4	858.2	1,032.0	1,043.8	840.5	7,809.8
TVA	496.4	407.2	172.8	104.0	20.2	12.0	40.4	96.3	46.0	1,395.3
WEC	11.2	113.8	393.7	172.7	316.2	118.3	174.5	492.0	546.0	2,338.4
Total	5,010.2	3,998.4	4,167.3	3,524.0	3,338.0	3,631.7	4,790.9	4,750.8	3,746.3	36,957.6

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Table 4-6 Day-ahead gross export volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-6)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	817.4	735.8	988.6	846.7	831.3	628.1	708.0	600.8	714.1	6,870.8
ALTW	913.4	939.6	637.7	749.0	389.5	510.2	422.7	592.4	433.5	5,588.0
AMIL	6.6	2.7	2.3	4.9	2.6	0.0	2.4	43.5	11.4	76.4
CIN	328.6	255.5	226.3	190.1	227.2	264.5	281.7	243.7	311.5	2,329.1
CPLE	138.5	98.8	100.4	102.0	112.1	164.9	166.2	129.7	103.4	1,116.0
CPLW	186.1	168.1	185.1	180.0	158.7	176.2	186.9	186.0	147.8	1,574.9
CWLP	0.7	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
DUK	36.0	76.3	54.8	49.1	17.9	31.3	35.1	21.3	114.5	436.2
EKPC	31.9	22.8	1.1	0.0	0.0	0.0	0.0	1.4	0.3	57.5
FE	221.9	278.7	301.4	220.3	216.3	217.1	325.5	304.5	357.4	2,443.2
IPL	563.2	350.9	310.4	321.3	173.5	107.0	135.0	209.3	112.4	2,283.0
LGEE	19.4	9.1	1.4	1.2	1.7	1.1	2.1	2.5	0.0	38.5
LIND									2.7	2.7
MEC	145.9	90.0	173.4	185.3	209.3	252.9	216.0	207.8	450.4	1,931.0
MECS	403.0	227.2	238.1	345.8	261.3	192.7	221.1	239.9	133.9	2,262.9
NEPT	326.4	403.8	446.4	402.1	436.6	472.3	496.9	491.7	408.7	3,884.9
NIPS	518.2	569.3	561.8	402.6	421.8	213.6	419.9	519.4	743.0	4,369.6
NYIS	731.6	438.0	645.2	768.9	613.8	683.2	832.7	1,000.7	863.6	6,577.8
OVEC	31.1	23.1	24.5	24.5	4.2	0.9	3.2	5.1	45.1	161.7
TVA	13.9	22.6	21.1	22.2	14.8	54.8	22.4	16.7	68.7	257.2
WEC	63.7	56.8	41.3	55.5	47.2	89.6	131.1	57.3	136.2	678.7
Total	5,497.4	4,769.2	4,961.3	4,871.6	4,139.8	4,060.4	4,608.9	4,873.7	5,158.6	42,940.9

Interface Pricing

Table 4-7 Active interfaces: January through September 2009 (See 2008 SOM, Table 4-7)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
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			
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 2008 SOM, Figure 4-4)

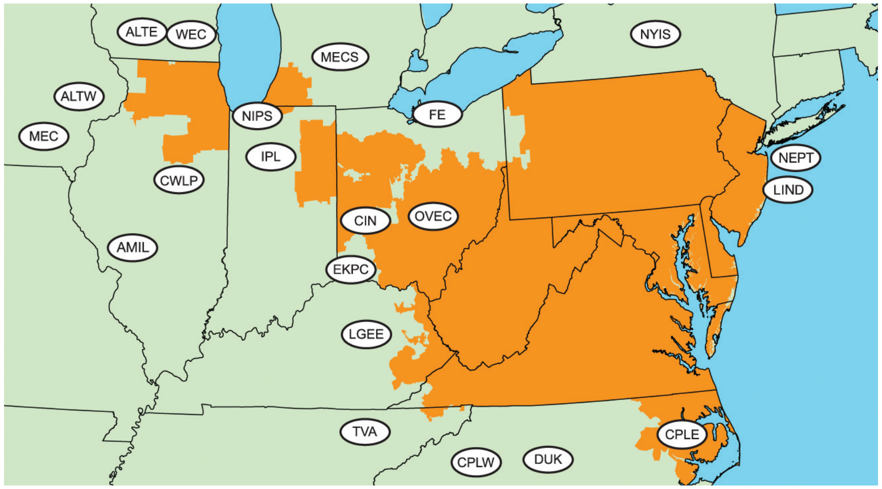

Table 4-8 Active pricing points: January through September 2009 (See 2008 SOM, Table 4-8)

PJM 2009 Pricing Points			
LIND	MICHFE	MISO	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO
OVEC	SOUTHEXP	SOUTHIMP	

Interactions with Bordering Areas

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 2009 (See 2008 SOM, Figure 4-5)

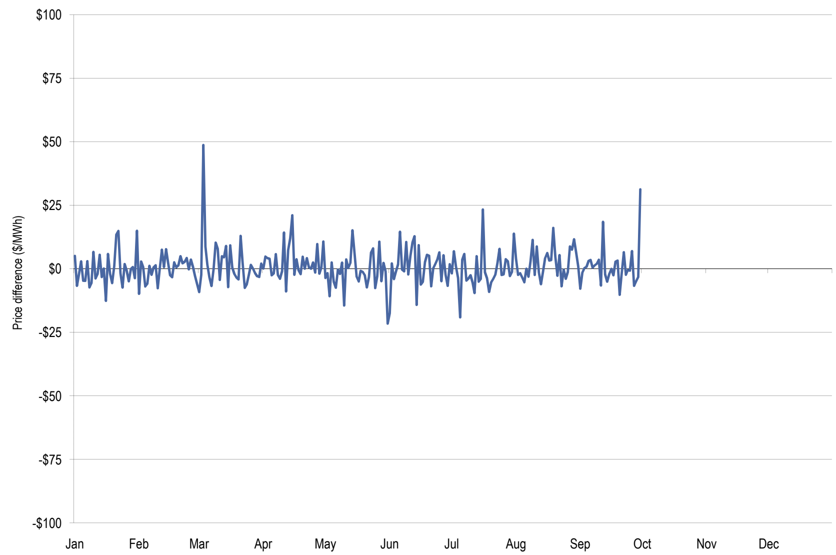

Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2009 (See 2008 SOM, Figure 4-6)

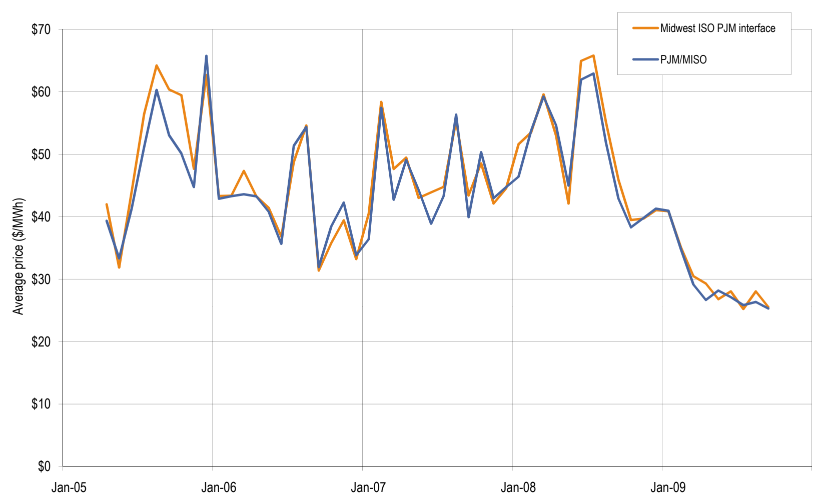

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Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): Calendar year 2008 and January through September 2009 (See 2008 SOM, Table 4-9)

	2008			2009		
	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$8.26	($6.56)	($2.86)	$5.18	($3.06)	($2.12)
Beaver Valley (PJM) & Mansfield (MISO)	$0.89	($14.42)	($2.38)	$1.81	($5.39)	($3.16)
Miami Fort (PJM) & (MISO)	$1.25	($12.27)	($4.16)	$2.11	($5.50)	($2.78)
Stuart (PJM) & (MISO)	$0.87	($12.04)	($4.77)	$1.81	($5.39)	($3.16)
PJM/MISO Interface	($1.16)	($15.34)	($3.51)	($0.56)	($8.28)	($2.64)
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 2009 (New Figure)

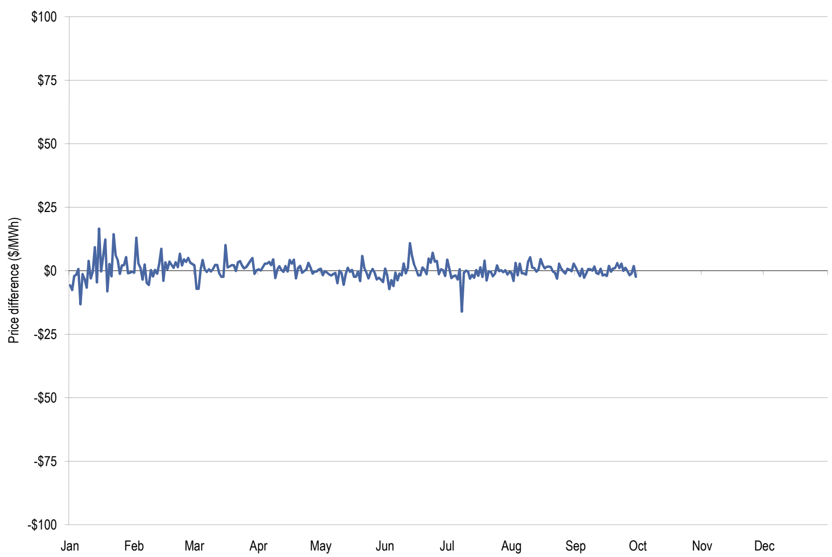


Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2009 (New Figure)

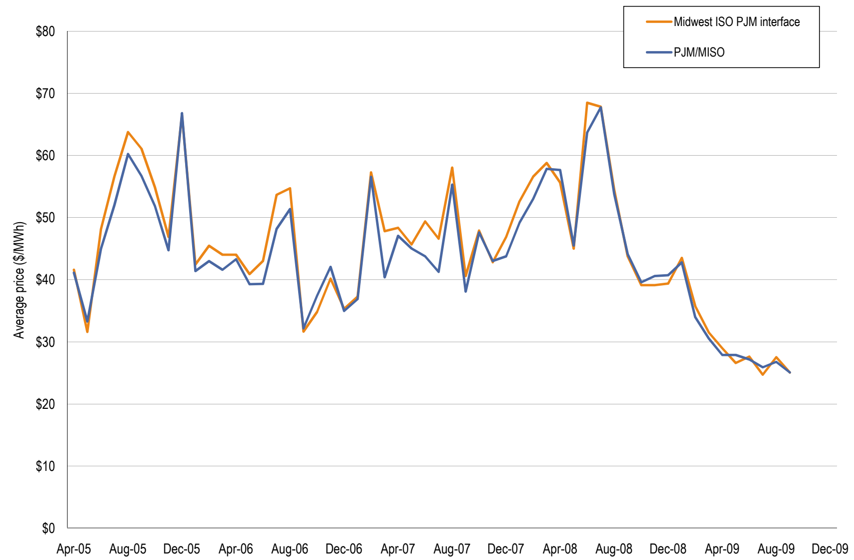


Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): Calendar year 2008 and January through September 2009 (New Table)

	2008			2009		
	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$9.19	($3.00)	($4.25)	$4.61	($2.20)	($2.89)
Beaver Valley (PJM) & Mansfield (MISO)	$3.40	($9.88)	($3.16)	$2.59	($5.33)	($1.79)
Miami Fort (PJM) & (MISO)	($0.05)	($11.17)	($5.32)	$2.01	($4.45)	($3.23)
Stuart (PJM) & (MISO)	($0.56)	($11.00)	($6.00)	$1.60	($4.40)	($3.70)
PJM/MISO Interface	($0.62)	($12.51)	($4.55)	($0.35)	($6.78)	($3.28)
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 2009 (See 2008 SOM, Figure 4-7)

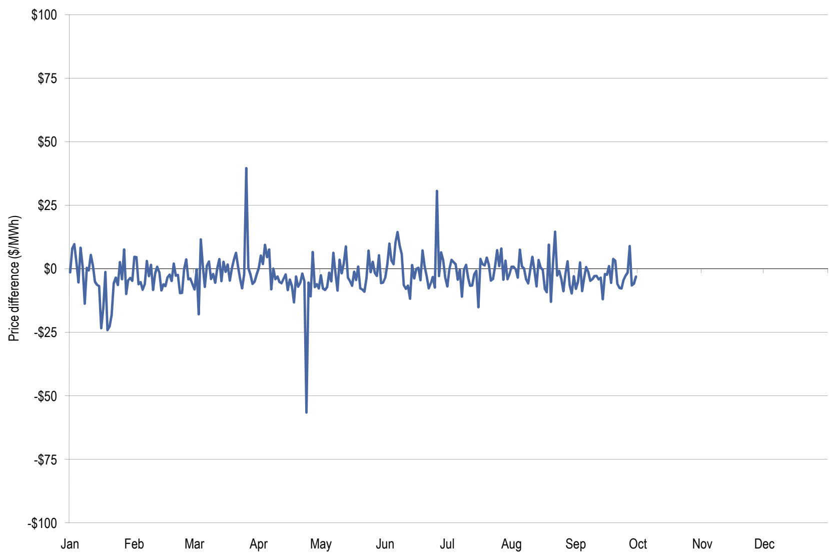


Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through September 2009 (See 2008 SOM, Figure 4-8)

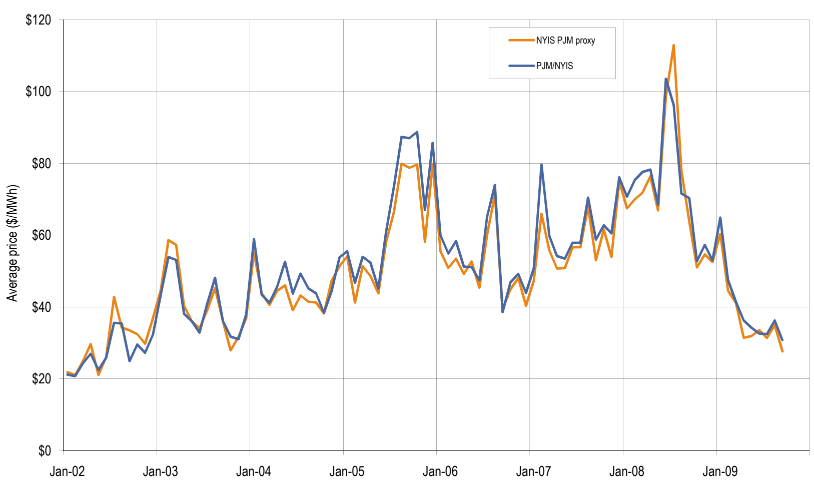


Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through September 2009 (New Figure)

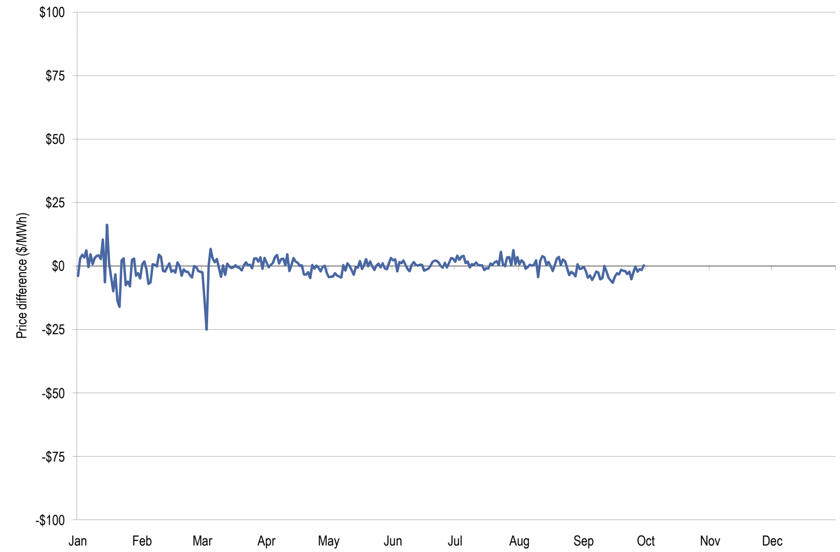
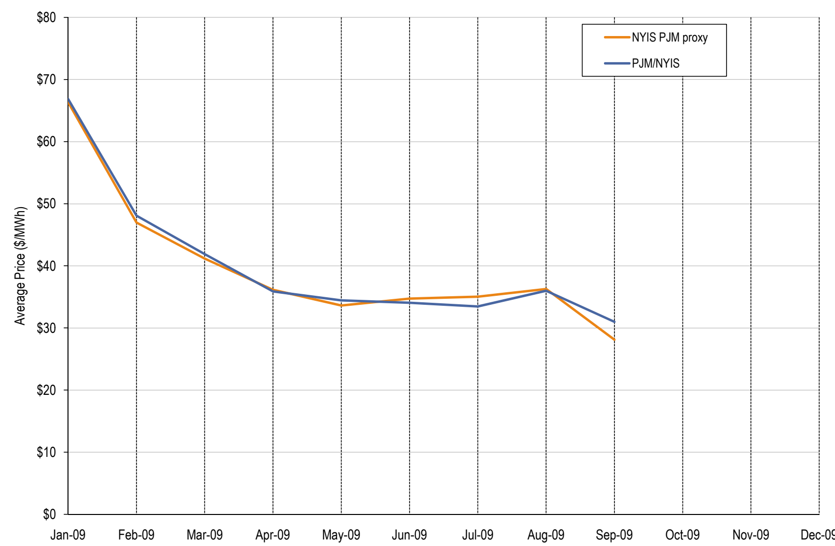


Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January through September 2009 (New Figure)



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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 2009 (See 2008 SOM, Figure 4-9)

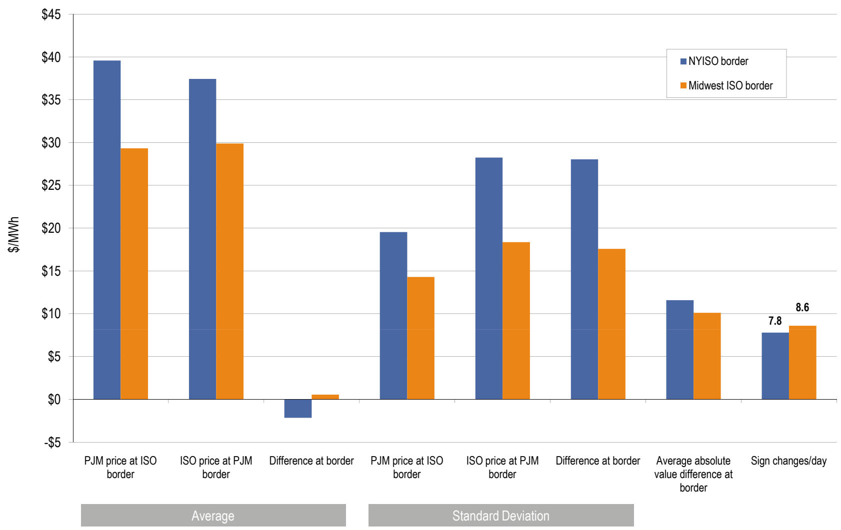
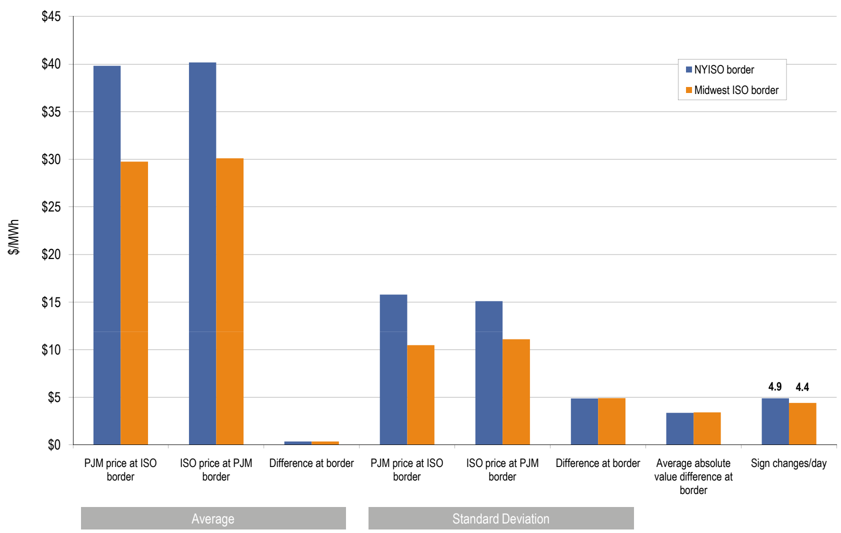


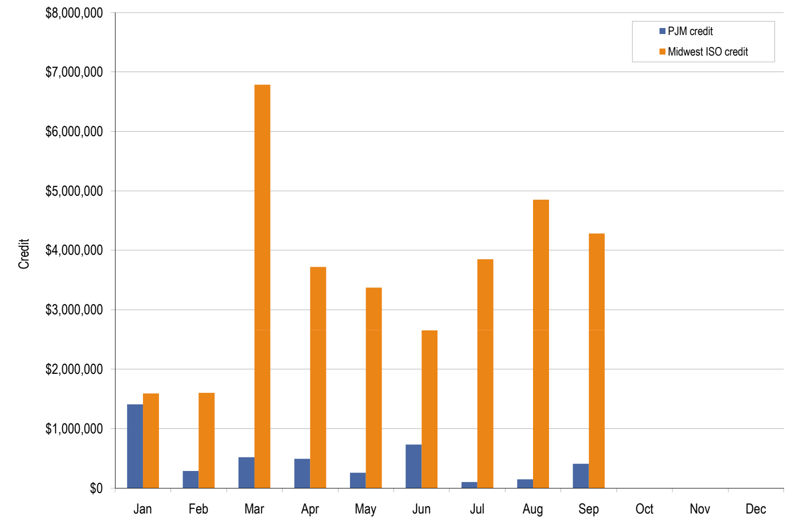
Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: January through September 2009 (New Figure)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement (JOA)

Figure 4-15 Credits for coordinated congestion management: January through September 2009 (See 2008 SOM, Figure 4-10)



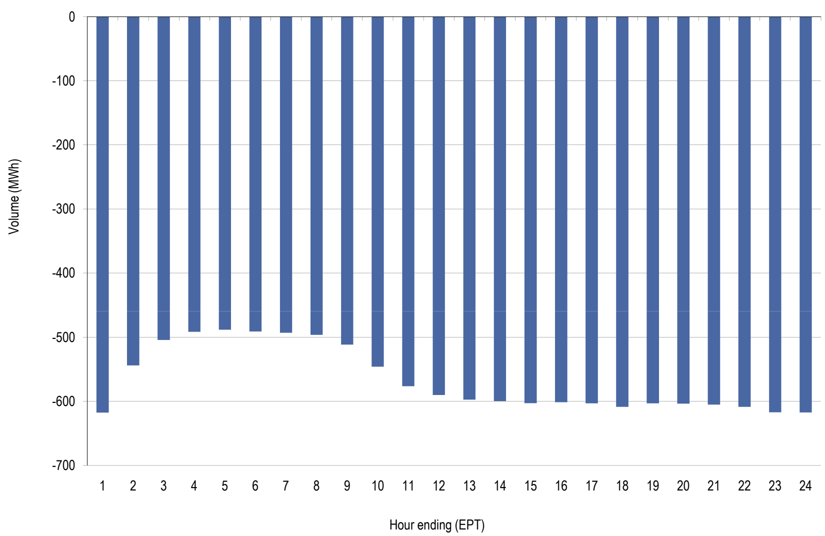
Con Edison and PSE&G Wheeling Contracts

Table 4-11 Con Edison and PSE&G wheeling settlement data: January through September 2009 (See 2008 SOM, Table 4-10)

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total Congestion Credit	$1,302,867	$1,832	$1,304,700	$3,676,287	$0	$3,676,287
Congestion Credit			$1,114,647			$3,651,446
Adjustments			$484,174			$14,563
Net Charge			($294,122)			$10,278

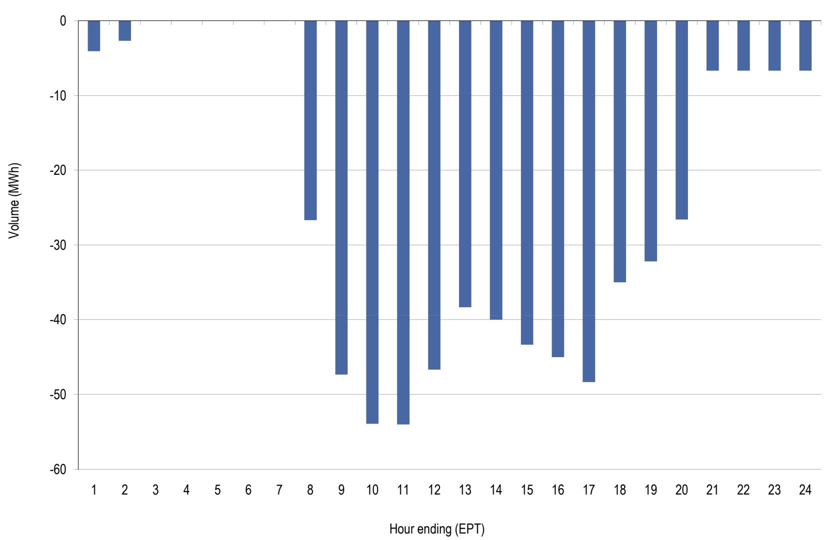
Neptune Underwater Transmission Line to Long Island, New York

Figure 4-16 Neptune hourly average flow: January through September 2009 (See 2008 SOM, Figure 4-11)



Linden Variable Frequency Transformer (VFT) facility

Figure 4-17 Linden hourly average flow: September 2009 (New Figure)



Interface Pricing Agreements with Individual Companies

Table 4-12 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (See 2008 SOM, Table 4-11)

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$50.58	$47.29	$47.29	$3.29	$3.29
PEC	$52.21	$47.29	$47.29	$4.93	$4.93
NCMPA	$50.66	$47.29	$47.29	$3.37	$3.37

Table 4-13 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through September 2009 (See 2008 SOM, Table 4-11)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.59	$31.00	$29.56	$29.56	$1.03	$1.44
PEC	$31.01	$32.44	$29.56	$29.56	$1.45	$2.89
NCMPA	$30.78	$30.85	$29.56	$29.56	$1.23	$1.30

Figure 4-18 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2009 (New Figure)

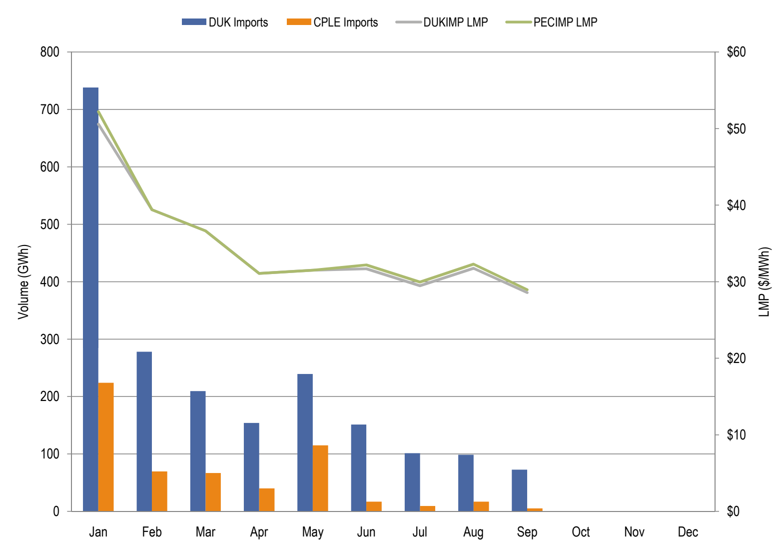


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Figure 4-19 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2009 (New Figure)

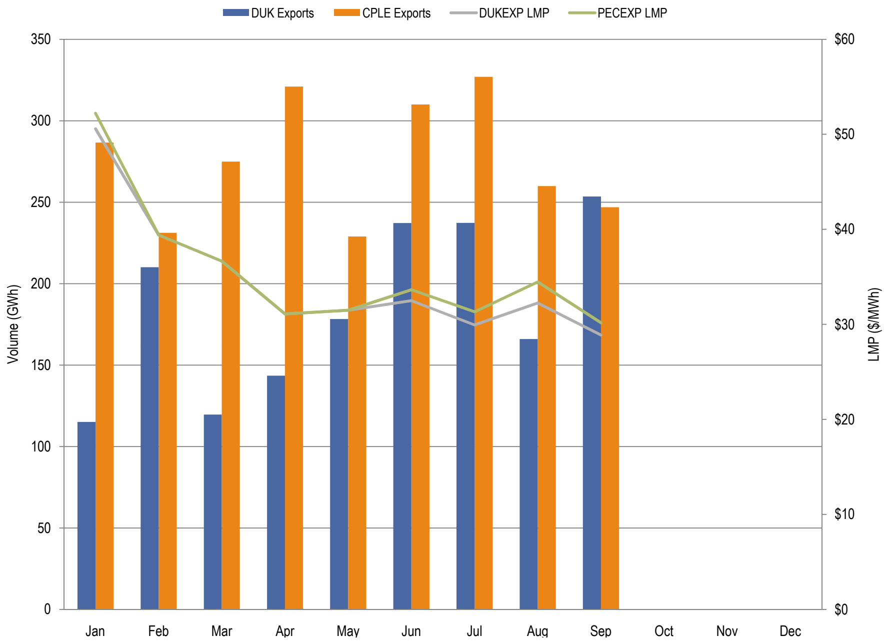


Figure 4-20 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2009 (New Figure)

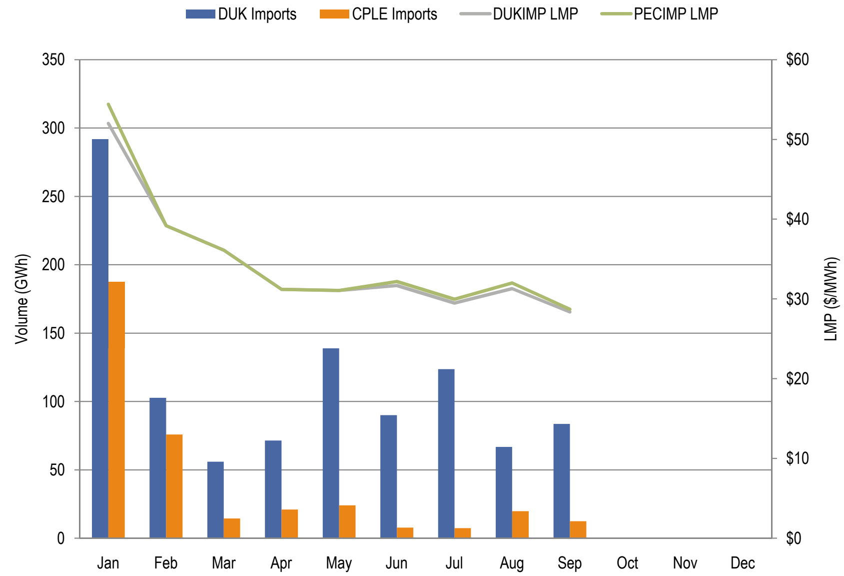


Figure 4-21 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2009 (New Figure)

Table 4-14 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (New Table)

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$52.01	$48.59	$48.59	$3.42	$3.42
PEC	$54.41	$48.59	$48.59	$5.82	$5.82
NCMPA	$52.10	$48.59	$48.59	$3.51	$3.51

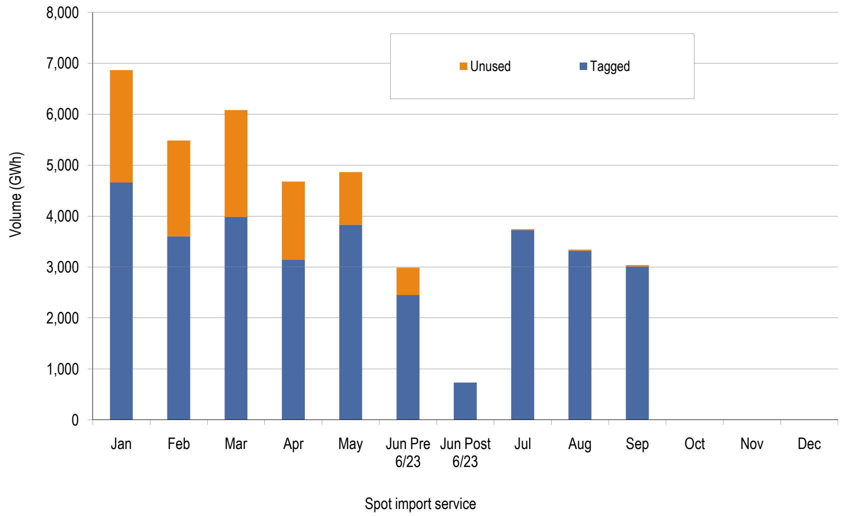
Table 4-15 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through September 2009 (New Table)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.57	$31.28	$29.92	$29.92	$0.65	$1.35
PEC	$31.13	$32.62	$29.92	$29.92	$1.21	$2.70
NCMPA	$30.91	$30.98	$29.92	$29.92	$0.99	$1.05

Interchange Transaction Issues

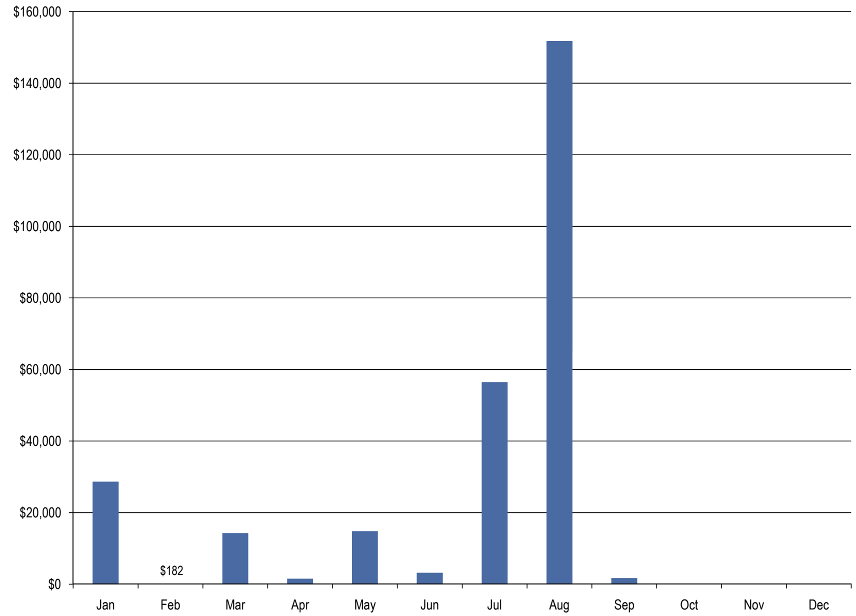
Spot Import

Figure 4-22 Spot import service utilization: January through September 2009 (See 2008 SOM, Figure 4-12)



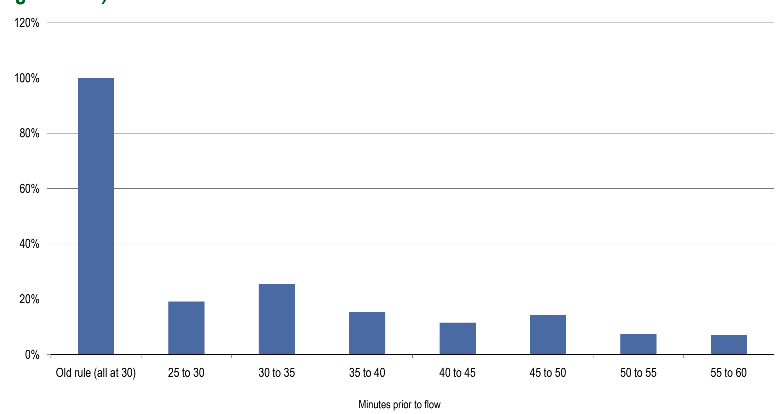
Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-23 Monthly uncollected congestion charges: January through September 2009 (See 2008 SOM, Figure 4-13)



Ramp Availability

Figure 4-24 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through September 2009 (See 2008 SOM, Figure 4-14)



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Curtailment of Transactions

TLRs

Figure 4-25 PJM and Midwest ISO TLR procedures: Calendar year 2008 and January through September 2009 (See 2008 SOM, Figure 4-15)

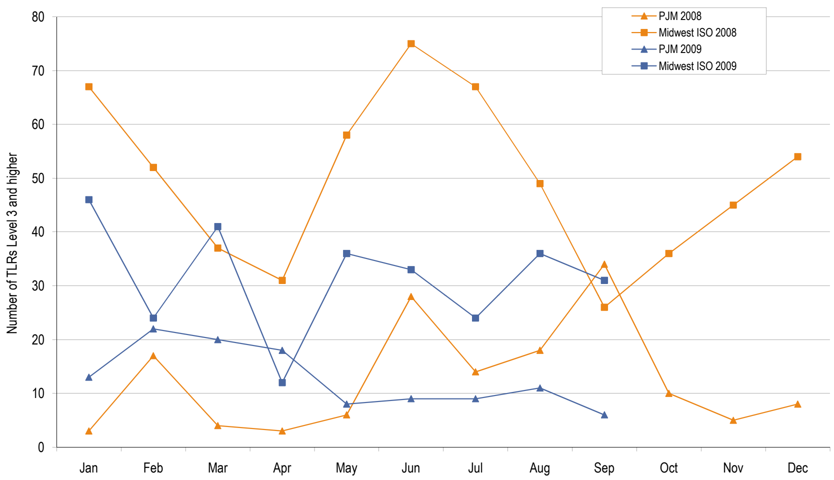


Figure 4-26 Number of different PJM flowgates that experienced TLRs: Calendar year 2008 and January through September 2009 (See 2008 SOM, Figure 4-16)

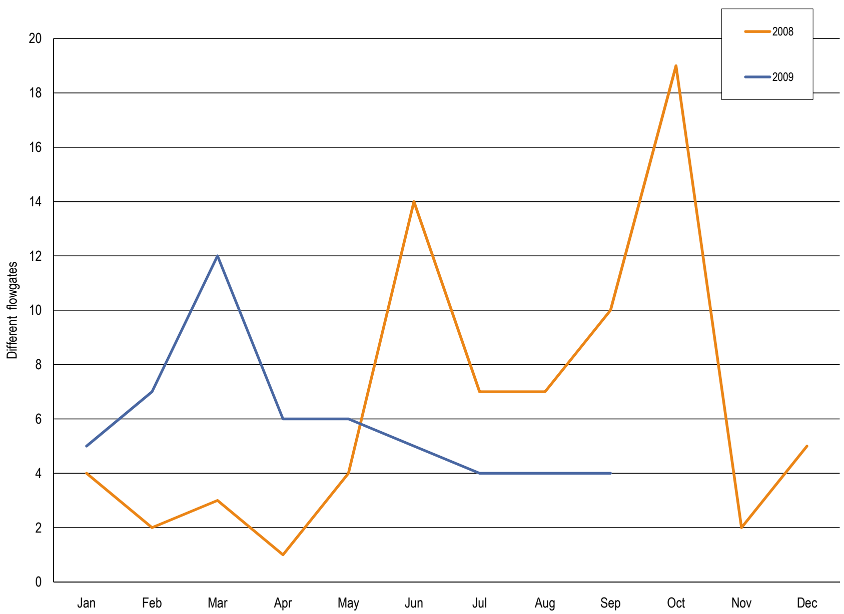
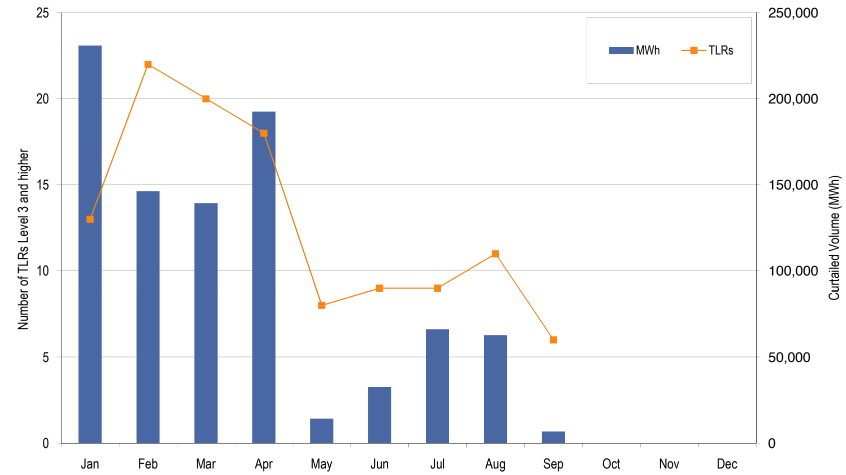
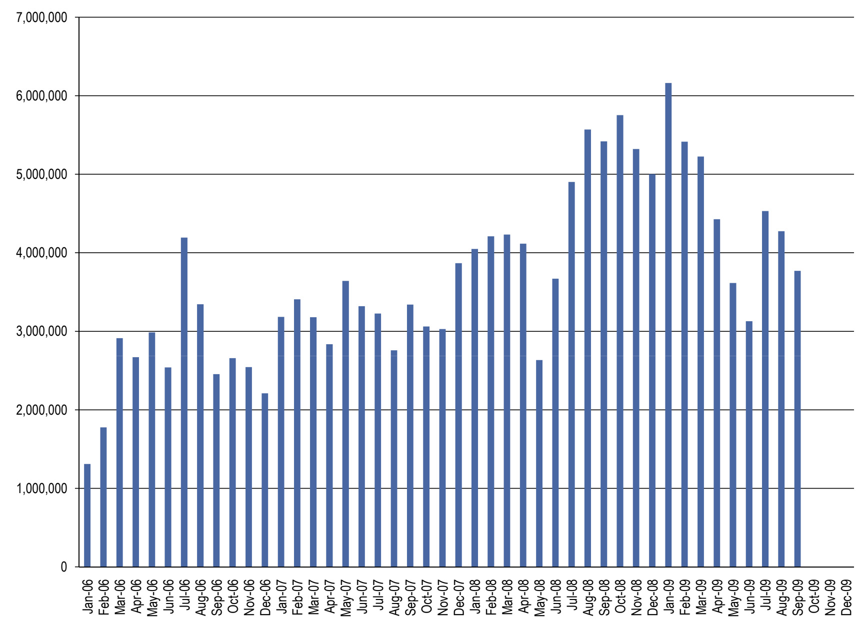


Figure 4-27 Number of PJM TLRs and curtailed volume: January through September 2009 (See 2008 SOM, Figure 4-17)



Up-To Congestion

Figure 4-28 Monthly up-to congestion bids in MWh: January 2006 through September 2009 (See 2008 SOM, Figure 4-18)



Loop Flows

Table 4-16 Net scheduled and actual PJM interface flows (GWh): January through September 2009 (See 2008 SOM, Table 4-12)

Net scheduled and actual PJM interface flows: JAN - SEP 2009				Difference
	Actual	Net Scheduled	Difference (GMh)	(percent of net scheduled)
ALTE	(4,591)	(763)	(3,828)	502%
ALTW	(1,595)	(1,023)	(572)	56%
AMIL	6,622	89	6,533	7340%
CIN	1,931	1,301	630	48%
CPLE	5,096	(1,079)	6,175	(572%)
CPLW	(1,319)	(623)	(696)	112%
CWLP	(471)	-	(471)	0%
DUK	(2,196)	382	(2,578)	(675%)
EKPC	508	(556)	1,064	(191%)
FE	(831)	(1,963)	1,132	(58%)
IPL	1,621	92	1,529	1662%
LGEE	1,035	803	232	29%
LIND	(9)	(9)	-	0%
MEC	(1,596)	(222)	(1,374)	619%
MECS	(7,471)	3,065	(10,536)	(344%)
NEPT	(3,718)	(3,718)	-	0%
NIPS	(1,851)	(310)	(1,541)	497%
NYIS	(1,499)	(3,470)	1,971	(57%)
OVEC	6,097	9,268	(3,171)	(34%)
TVA	2,960	346	2,614	755%
WEC	2,404	(422)	2,826	(670%)
YTD Total	1,127	1,188	(61)	(5%)

Loop Flows at the PJM/MECS and PJM/TVA Interfaces

Figure 4-29 PJM/MECS Interface average actual minus scheduled volume: January through September 2009 (See 2008 SOM, Figure 4-19)

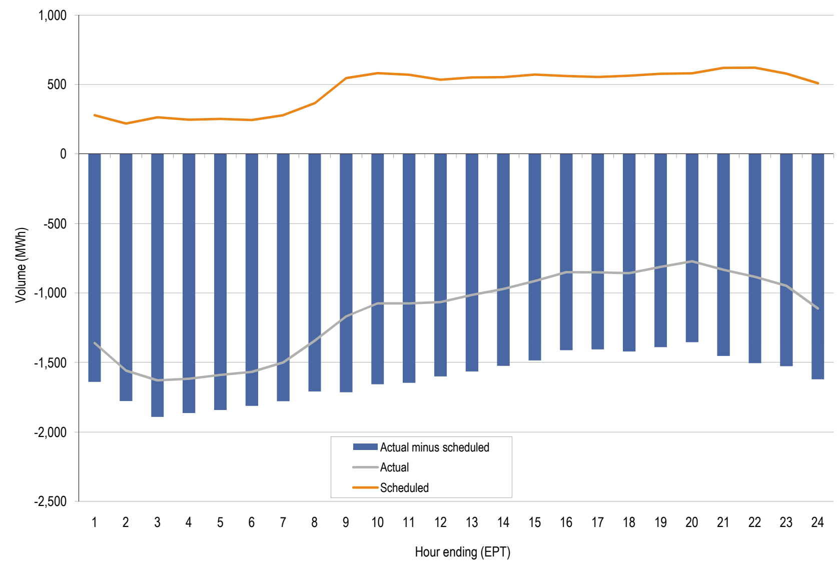
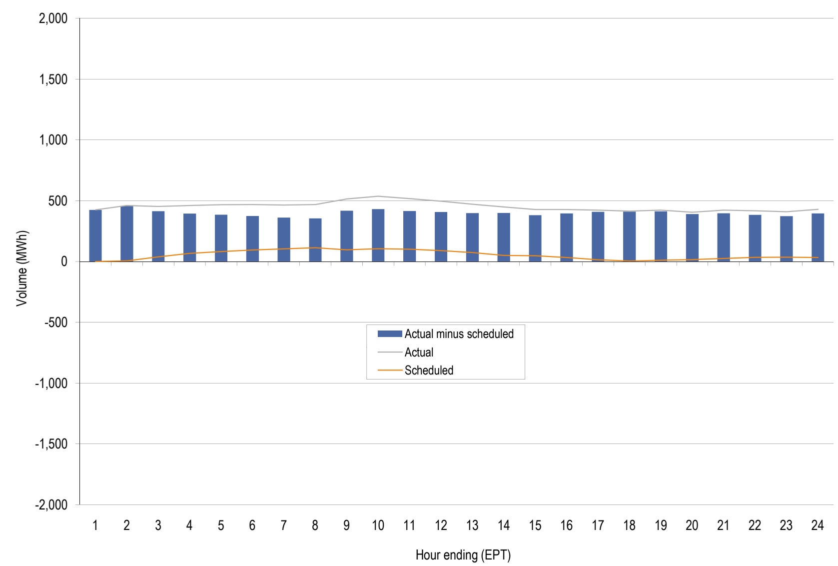


Figure 4-30 PJM/TVA average flows: January through September 2009 (See 2008 SOM, Figure 4-21)



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Loop Flows at PJM's Southern Interfaces

Figure 4-31 Southwest actual and scheduled flows: January 2006 through September 2009 (See 2008 SOM, Figure 4-22)

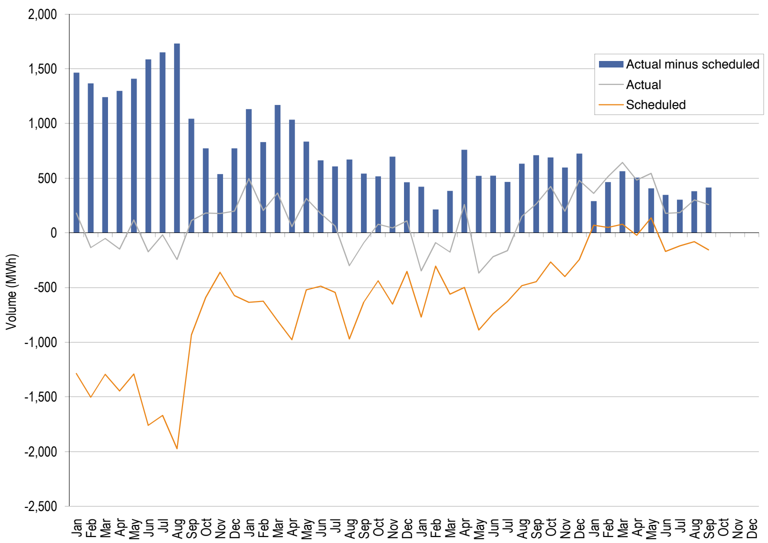
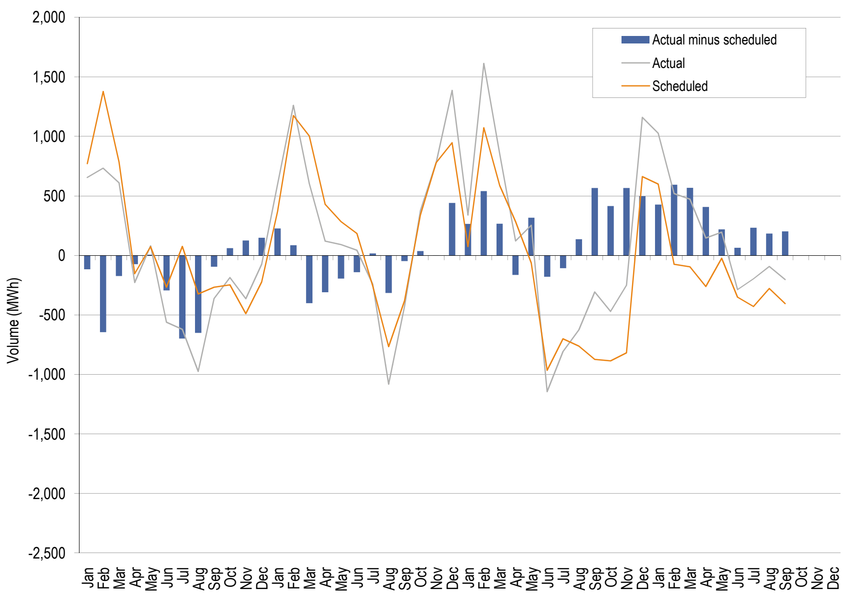


Figure 4-32 Southeast actual and scheduled flows: January 2006 through September 2009 (See 2008 SOM, Figure 4-23)



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SECTION 5 - CAPACITY MARKETS

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 offering them into the capacity market, or 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 2009, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the RPM Capacity Market design was implemented in the PJM region, replacing the CCM Capacity Market 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 (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 delivery year, First, Second and Third Incremental RPM Auctions are held for each delivery year, occurring 23, 13 and four months, respectively, prior to the delivery year.[2] Prior to the 2012/2013 delivery year, the second incremental auction is conducted when there is an increase in the region's unforced capacity obligations as a result of a load forecast increase. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held to address significant unexpected changes that occur after the BRA, such as a delay in planned large transmission upgrades that results in the need for procurement of additional capacity.

RPM prices are locational and may vary depending on transmission constraints.[3] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the fixed resource requirement (FRR) option. Under RPM, participation by LSEs is mandatory, except for 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. Under RPM there are performance incentives for generation. 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 do not limit prices offered by new entrants. Demand-side resources may be offered directly into RPM auctions and receive the clearing price.

Market Structure

- **Supply.** Total internal capacity increased 350.2 MW from 156,968.0 MW on June 1, 2008, to 157,318.2 MW on June 1, 2009.[4] This increase was the result of 439.2 MW of new generation, 74.1 MW of generation uprates, and 220.6 MW of demand resource (DR) mods, offset in part by 383.7 MW from higher EFORds.

  In the 2010/2011, 2011/2012, and 2012/2013 auctions, new generation increased 3,271.9 MW; 651.9 MW came out of retirement and net generation deratings were 2,994.9 MW, for a total of 928.9 MW. DR and Energy Efficiency (EE) offers increased 9,409.3 MW through June 1, 2012 offset in part by 890.3 MW from higher EFORds. The reclassification of the Duquesne resources as internal added 3,817.2 MW to total internal capacity. The net effect from June 1, 2009, through June 1, 2012, was an increase in total internal capacity of 12,635.1 MW (8.0 percent) from 157,318.2 MW to 169,953.3 MW.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2009 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 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.

4 Unless otherwise specified, all volumes are in terms of UCAP.

In the 2009/2010 auction, 17 more generating resources made offers than in the 2008/2009 RPM Auction. The increase included eight new combustion turbine (CT) resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW) while the remaining six resources included more resources imported, fewer resources exported, a decrease in resources excused from offering into the auction and fewer resources removed from the auction under the fixed resource requirement (FRR) option.

In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The net increase of 11 resources consisted of 15 new resources, four reactivated resources, three resources from the FRR participant, and one resource previously excused, offset by three retired resources, four deactivated resources, three resources exported from PJM, and two resources excused from offering. There were seven new CT resources (270.5 MW), three new diesel resources (16.4 MW), five new wind resources (120.0 MW) and four reactivated resources (165.0 MW) for a total of 19 resources. There were three resources that retired (348.4 MW), four resources that were deactivated (59.6 MW) and an additional three resources exported out of PJM (521.5 MW) for a total of 10 resources.

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The net increase of 21 resources 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 FRR resources that did not offer (64.2 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).[5] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two combustion turbine resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new 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).

- **Demand.** There was a 2,545.5 MW increase in the RPM reliability requirement from 150,934.6 MW on June 1, 2008 to 153,480.1 MW on June 1, 2009. On June 1, 2009, PJM EDCs and their affiliates maintained a 79.3 percent market share of load obligations under RPM, down from 80.1 percent on June 1, 2008.

- **Market Concentration.** For the 2009/2010, 2010/2011, 2011/2012, and 2012/2013 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2009/2010 BRA, 2009/2010 Third IA, 2010/2011 BRA, 2011/2012 BRA, and 2011/2012 First IA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test. Six participants included in the incremental supply of EMAAC passed the test. Offer caps were applied to all sell offers that did not pass the test.

- **Imports and Exports.** Net exchange increased 1,688.3 MW from June 1, 2008 to June 1, 2009. Net exchange, which is imports less exports, increased due to an increase in imports of 45.1 MW and a decrease in exports of 1,643.2 MW.

- **Demand-Side Resources.** Under RPM, demand-side resources in the Capacity Market increased by 3,206.9 MW from 4,167.5 MW on June 1, 2008 to 7,374.4 MW on June 1, 2009. 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 Energy Efficiency (EE) resources.

5 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.

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- **Net Excess.** Net excess increased 3,254.4 MW from 5,011.1 MW on June 1, 2008 to 8,265.5 MW on June 1, 2009.

Market Conduct

- **2009/2010 RPM Base Residual Auction.** Of the 1,093 generating resources which submitted offers, unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2009/2010 Third Incremental Auction.** Of the 267 generating resources which submitted offers, 255 resources chose the offer cap option of 1.1 times the BRA clearing price (95.5 percent).[6] Unit-specific offer caps were calculated for two resources (0.7 percent). Offer caps of all kinds were calculated for five resources (1.9 percent), of which one was based on the technology specific default (proxy) ACR posted by the MMU.

- **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 posted by the MMU.

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 303 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2011/2012 RPM First Incremental Auction.** Of the 129 generating resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.8 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 posted by the MMU.

- **2012/2013 RPM Base Residual Auction.**[7] 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 posted by the MMU.

6 124 FERC ¶ 61,140 (2008).

7 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>

Generator Performance

- **Forced Outage Rates.** PJM EFORd remained constant at 7.4 percent from 2008 to 2009 (January through August). PJM EFORp decreased from 4.9 percent in 2008 to 3.8 percent in 2009 (January through August).[8] The forced outage rates are for the entire PJM footprint.

- **Generator Performance Factors.** The equivalent availability factor increased from 83.4 percent for the period January through May 2009 to 86.7 percent for the year to date period January through August 2009. This increase was primarily due to a significant decrease in the equivalent planned outage factor and equivalent maintenance outage factor across all unit types during the months June through August 2009.

- **Outages Outside of Management Control (OMC).** PJM permits units to use a forced outage rate (XEFORd) for purposes of selling unforced capacity in the Capacity Market, calculated excluding outages that are designated outside management control. Use of different forced outage metrics for defining reliability targets and for determining available capacity to meet those reliability targets introduces an inconsistency. For example, the EFORd for CTs is 8.8 percent, while the XEFORd for CTs is 7.6 percent. Using artificially reduced outage rates for determining unforced capacity that can be sold in RPM auctions will result in the sale of capacity that is not actually available. A forced outage is a forced outage, from the perspective of system reliability, regardless of the cause.

Conclusion

Market Design

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will

8 2008 data are for the 12 months ended December 31, 2008, as downloaded from the PJM GADS database on January 23, 2009. 2009 data are for the 8 months ending August 31, 2009, as downloaded from the PJM GADS database on October 26, 2009. 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.

not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to also have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues. This hybrid approach would include both a capacity market and scarcity pricing in the energy market.

The definition of the capacity product is central to refining the market rules governing the sale and purchase of capacity. The current definition of capacity includes several components: the obligation to offer the energy of the unit into the day ahead market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; and the obligation that the energy output from the resource be deliverable to load in PJM.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the day ahead market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the day ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the day ahead energy market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the day ahead energy market. A unit which is not capable of supplying energy consistent with its day ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing, it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the hours defined as critical, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy when called upon during any of the hours defined as critical, it should receive no capacity revenues. This approach to performance is also consistent with the reduction or elimination of administrative penalties associated with failure to meet capacity tests, for example.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecasts, or those reflected in results from prior years. Scarcity revenues are episodic and unlikely to be fully reflected in historical data or in forward curves, even if such curves were based on a liquid market three years forward, which they are not, and reflected locational results, which they do not. The most straightforward way to ensure that such double payment does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

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Market Power

The RPM Capacity Market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective and explicitly limiting the exercise of market power.

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

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

RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the three pivotal supplier test.

Competitive prices are the lowest possible prices, consistent with the resource costs. But, competitive prices are not necessarily low prices. In the Capacity Market, it is essential that the cost of new entry (CONE) be based on the actual resource costs of bringing a new capacity resource into service. If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new entry.

The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives in the RPM Capacity Market design need to be strengthened. The Energy Market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high and if they are successful, this will also result in lower forced outage rates. Well designed scarcity pricing could also provide strong, complementary incentives for reduced outages during high load periods. It would be preferable to rely on strong market-based incentives for capacity resource performance rather than the current structure of penalties, which has its own incentive effects.

Results

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

The MMU found serious market structure issues, but no exercise of market power in the PJM Capacity Market during the first nine months of 2009. 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 2009.

RPM Capacity Market

Table 5-1 Internal capacity: June 1, 2008, through May 31, 2012[9, 10] (See 2008 SOM, Table 5-1)

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL-South	PSEG-North
Total internal capacity @ 01-Jun-08	156,968.0	72,889.5			10,777.1		
New generation	439.2	109.9			0.0		
Units out of retirement	0.0	0.0			0.0		
Generation capmods	74.1	(149.7)			(298.2)		
DR mods	220.6	163.2			42.3		
Net EFORd effect	(383.7)	0.0			(176.0)		
Total internal capacity @ 01-Jun-09	157,318.2	73,012.9			10,345.2	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

9 The RTO includes all LDAs. MAAC+APS and MAAC include EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. Maps of the LDAs can be found in the *2008 State of the Market Report for PJM*, Appendix A, "PJM Geography."

10 The UCAP MW value attributed to the reclassification of Duquesne units differs from the value reported in the *2008 State of the Market Report for PJM* as a result of generation cap mods, DR and EE mods, and EFORd changes.

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Demand

Table 5-2 PJM Capacity Market load obligation served: June 1, 2009 (See 2008 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	68,626.9	11,774.2	25,831.0	1,033.8	10,416.7	509.1	15,695.3	133,887.0
Percent of total obligation	51.2%	8.8%	19.3%	0.8%	7.8%	0.4%	11.7%	100.0%

Market Concentration

Preliminary Market Structure Screen

Table 5-3 Preliminary market structure screen results: 2008/2009 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-3)

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2008/2009				
RTO	18.5%	879	1	Fail
EMAAC	33.1%	2180	1	Fail
SWMAAC	47.5%	4290	1	Fail
2009/2010				
RTO	18.4%	853	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	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

Auction Market Structure

Table 5-4 RSI results: 2008/2009 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-4)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2008/2009 BRA			
RTO	0.61	65	65
EMAAC	0.25	10	10
SWMAAC	0.00	3	3
2008/2009 Third IA			
RTO/EMAAC	0.87	40	22
SWMAAC	0.00	3	3
2009/2010 BRA			
RTO	0.60	66	66
MAAC+APS	0.37	21	21
SWMAAC	0.00	3	3
2009/2010 Third IA			
RTO	0.64	40	40
MAAC+APS	0.14	8	8
2010/2011 BRA			
RTO	0.60	68	68
DPL-South	0.00	2	2
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

Imports and Exports

Table 5-5 PJM capacity summary (MW): June 1, 2008, through May 31, 2012[11, 12] (See 2008 SOM, Table 5-5)

	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12
Installed capacity (ICAP)	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7
Unforced capacity	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8
Cleared capacity	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5
RPM reliability requirement (pre-FRR)	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5
RPM reliability requirement (less FRR)	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4
RPM net excess	5,011.1	8,265.5	1,149.2	3,156.6	5,754.4
Imports	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6
Exports	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)
Net exchange	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5
DR cleared	536.2	892.9	939.0	1,364.9	7,047.2
EE cleared					568.9
ILR	3,608.1	6,481.5	2,110.5	1,593.8	
FRR DR	452.8	423.6	452.9	452.9	488.1
Short-Term Resource Procurement Target					3,343.3

11 FRR DR values have been revised since the *2008 State of the Market Report for PJM* was posted.

12 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2008/2009 and 2009/2010, certified ILR was used in the calculation. For 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR including FRR DR for the first four base residual auctions. FRR DR is not subtracted in the calculation for the 2011/2012 auction, because PJM forecast ILR excluding FRR DR for the 2011/2012 BRA. 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.

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Demand-Side Resources

Table 5-6 RPM load management and energy efficiency statistics: June 1, 2008 through May 31, 2012[13] (See 2008 SOM, Table 5-6)

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
DR cleared	559.4			169.0	309.2		
ILR certified	3,608.1			622.6	219.7		
RPM load management @ 01-June-2008	4,167.5			791.6	528.9		
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	939.0					14.9	
ILR forecast - FRR DR	1,657.6					22.2	
RPM load management @ 01-June-2010	2,596.6					37.1	
DR cleared	1,364.9						
ILR forecast	1,593.8						
RPM load management @ 01-June-2011	2,958.7						
DR cleared	7,047.2		4,723.7	1,638.4		64.6	67.6
EE cleared	568.9		179.9	20.0		0.0	0.9
RPM load management @ 01-June-2012	7,616.1		4,903.6			64.6	68.5

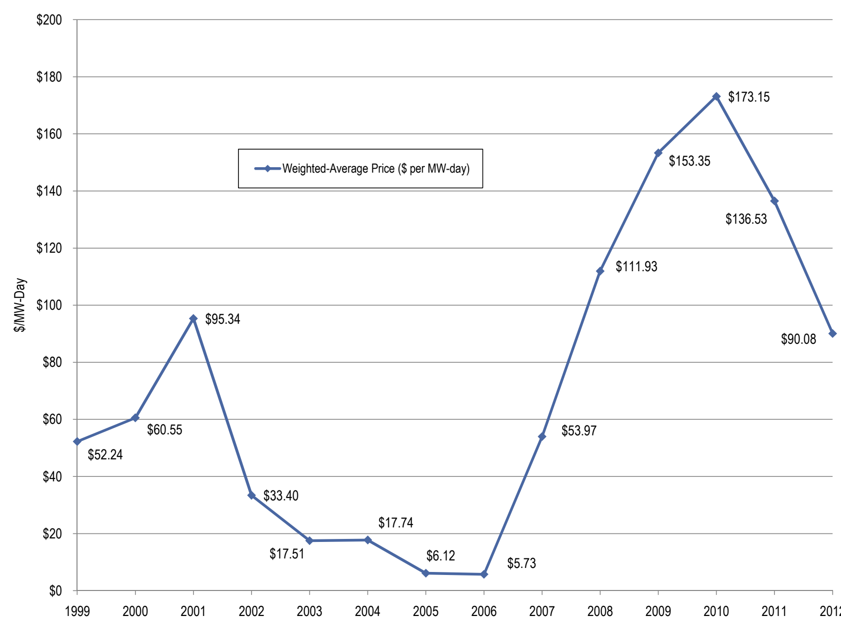
13 PJM used forecast ILR, including FRR DR, for the first four base residual auctions. For 2008/2009 and 2009/2010, certified ILR data were used in the calculation here because the certified ILR data are now available. For 2010/2011, forecast ILR less FRR DR is used and will continue to be used until certified ILR data are available. PJM used forecast ILR, excluding FRR DR, for the 2011/2012 BRA. Therefore, FRR DR is not subtracted in the calculation here for the 2011/2012 auction. Effective the 2012/2013 delivery year, ILR was eliminated and the Energy Efficiency (EE) resource type was eligible to be offered in RPM auctions.

Market Performance

Table 5-7 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-10)

	RPM Clearing Price ($ per MW-day)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
2007/2008 BRA	$40.80			$197.67	$188.54		
2008/2009 BRA	$111.92			$148.80	$210.11		
2008/2009 Third IA	$10.00				$223.85		
2009/2010 BRA	$102.04	$191.32			$237.33		
2009/2010 Third IA	$40.00	$86.00					
2010/2011 BRA	$174.29					$178.27	
2011/2012 BRA	$110.00						
2011/2012 First IA	$55.00						
2012/2013 BRA	$16.46		$133.37	$139.73		$222.30	$185.00

Figure 5-1 History of capacity prices: Calendar year 1999 through 2012[14, 15] (See 2008 SOM, Figure 5-1)



14 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2012 capacity prices are RPM weighted average prices.

15 The 2011 weighted average price has been revised since the *2008 State of the Market Report for PJM* was posted to reflect the 2011/2012 First IA clearing.

Table 5-8 RPM cost to load: 2008/2009 through 2012/2013 RPM Auctions[16, 17, 18, 19] (See 2008 SOM, Table 5-11)

	Net Load Price ($/MW-Day)	UCAP Obligation (MW)	Annual Charges
2008/2009 BRA			
RTO	$113.22	79,814.6	$3,298,362,289
EMAAC	$145.24	35,755.4	$1,895,486,718
SWMAAC	$183.03	15,684.6	$1,047,824,603
2009/2010 BRA			
RTO	$104.82	56,696.9	$2,169,117,837
MAAC+APS	$193.78	60,984.3	$4,313,445,473
SWMAAC	$224.86	16,205.7	$1,330,043,812
2010/2011 BRA			
RTO	$174.29	129,253.2	$8,222,552,183
DPL	$178.27	4,595.0	$298,989,987
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

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

17 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.

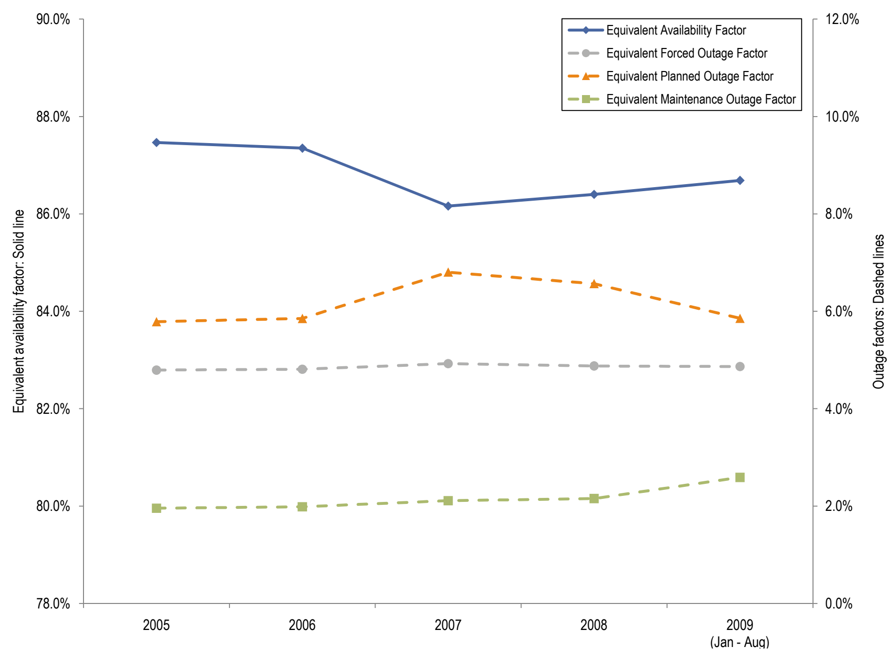
18 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second IA. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third IA. Effective with the 2012/2013 delivery year, the Final 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 2010/2011, 2011/2012, and 2012/2013 Net Load Prices and Obligation MW are not finalized.

19 The 2009/2010 Final Zonal UCAP Obligations and Final Zonal Capacity Prices have been updated since the *2009 Quarterly State of the Market Report for PJM: January through June* was posted, due to a PJM error with non zone load that was corrected by PJM.

Generator Performance

Generator Performance Factors

Figure 5-2 PJM equivalent outage and availability factors: Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-7)



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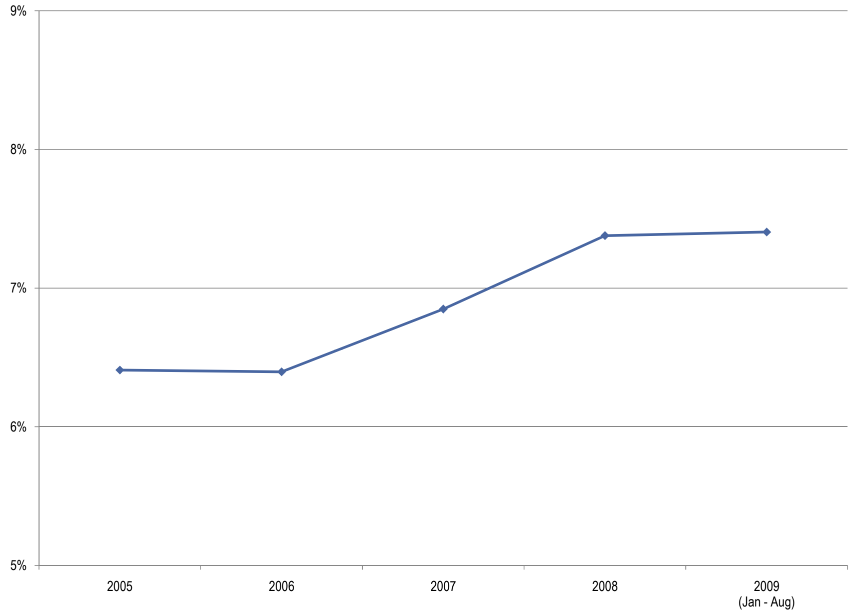
Generator Forced Outage Rates

Figure 5-3 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-8)



Components of EFORd

Table 5-9 Contribution to EFORd by unit type (Percentage points): Calendar years 2005 to 2009 (January through August)[20] (See 2008 SOM Table 5-17)

	2004	2005	2006	2007	2008	2009 (Jan - Aug)
Combined Cycle	0.5	0.6	0.5	0.4	0.4	0.5
Combustion Turbine	1.3	1.3	1.4	1.6	1.5	1.4
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.2	0.1	0.1	0.1	0.1	0.1
Nuclear	0.6	0.3	0.3	0.2	0.4	0.8
Steam	4.7	4.1	4.1	4.4	4.9	4.6
Total	7.3	6.4	6.4	6.8	7.4	7.4

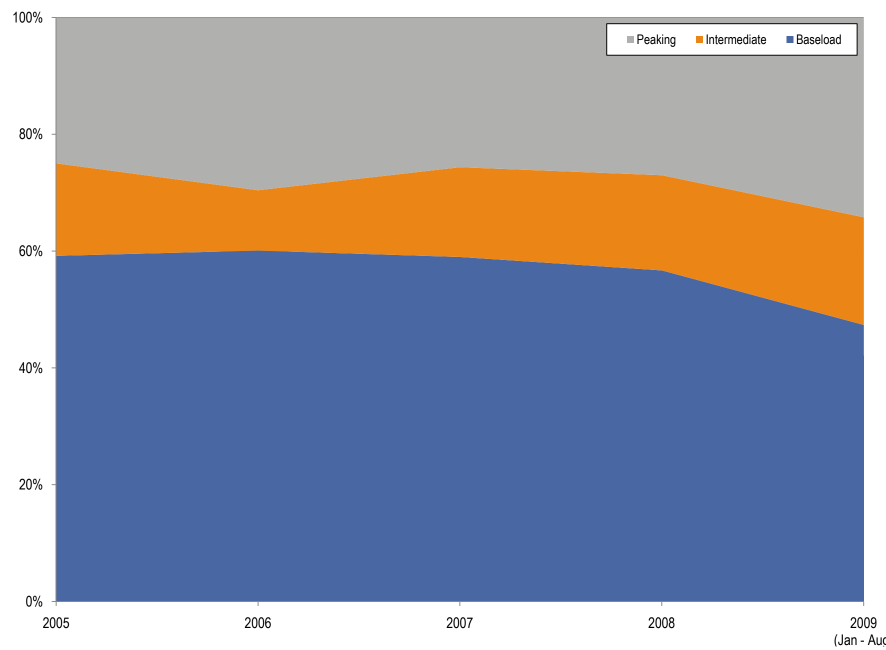
20 Calculated values presented in Section 5, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

Table 5-10 Five-year PJM EFORd data by unit type: Calendar years 2005 to 2009 (January through August) (See 2008 SOM Table 5-19)

	2004	2005	2006	2007	2008	2009 (Jan - Aug)
Combined Cycle	5.2%	5.0%	4.3%	3.5%	3.4%	3.7%
Combustion Turbine	9.0%	8.9%	9.4%	11.1%	10.9%	8.8%
Diesel	8.9%	14.0%	13.2%	11.8%	9.6%	9.7%
Hydroelectric	3.9%	2.5%	1.9%	2.3%	2.4%	2.8%
Nuclear	3.2%	1.6%	1.4%	1.3%	1.9%	4.2%
Steam	9.2%	8.1%	8.2%	8.8%	9.8%	9.6%
Total	7.3%	6.4%	6.4%	6.8%	7.4%	7.4%

Duty Cycle and EFORd

Figure 5-4 Contribution to EFORd by duty cycle: Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-9)



Forced Outage Analysis

Table 5-11 Outage cause contribution to PJM EFOF: January through August 2009 (See 2008 SOM Table 5-20)

	Percentage Point Contribution to EFOF	Contribution to EFOF
Low Pressure Turbine	0.87	17.8%
Boiler Tube Leaks	0.82	16.8%
Economic	0.46	9.5%
Electrical	0.28	5.7%
Generator	0.21	4.2%
Boiler Air and Gas Systems	0.19	3.9%
Fuel Quality	0.12	2.5%
Boiler Fuel Supply from Bunkers to Boiler	0.12	2.5%
Stack Emission	0.11	2.2%
High Pressure Turbine	0.10	2.1%
Condensing System	0.09	1.9%
Valve	0.09	1.8%
Inlet Air System and Compressors	0.08	1.7%
Controls	0.07	1.4%
Performance	0.07	1.4%
Miscellaneous (Steam Turbine)	0.07	1.4%
Miscellaneous	0.07	1.4%
Feedwater System	0.07	1.4%
Miscellaneous (Generator)	0.06	1.3%
All Other Causes	0.92	18.9%
Total	4.87	100.0%

Table 5-12 Contributions to Economic Outages: January through August 2009 (See 2008 SOM Table 5-21)

	Contribution to Economic Reasons
Lack of Fuel (OMC)	90.7%
Lack of Fuel (Non-OMC)	5.4%
Other Economic Problems	2.3%
Lack of Water (Hydro)	1.4%
Fuel Conservation	0.1%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.0%
Total	100.0%

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Table 5-13 Contribution to EFOF by unit type for the most prevalent causes: January through August 2009 (See 2008 SOM Table 5-22)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Low Pressure Turbine	0.2%	0.0%	0.0%	0.0%	77.5%	8.1%	17.8%
Boiler Tube Leaks	1.5%	0.0%	0.0%	0.0%	0.0%	23.9%	16.8%
Economic	3.4%	11.6%	4.1%	0.7%	0.0%	12.3%	9.5%
Electrical	13.4%	10.8%	0.6%	3.7%	7.9%	4.1%	5.7%
Generator	8.0%	2.7%	0.3%	61.8%	0.0%	3.4%	4.2%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	5.6%	3.9%
Fuel Quality	0.0%	0.0%	13.3%	0.0%	0.0%	3.6%	2.5%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	3.5%	2.5%
Stack Emission	0.0%	0.4%	0.3%	0.0%	0.0%	3.1%	2.2%
High Pressure Turbine	0.1%	0.0%	0.0%	0.0%	0.0%	3.0%	2.1%
Condensing System	0.1%	0.0%	0.0%	0.0%	0.5%	2.7%	1.9%
Valve	1.8%	0.0%	0.0%	0.0%	1.6%	2.1%	1.8%
Inlet Air System and Compressors	12.7%	16.0%	0.0%	0.0%	0.0%	0.0%	1.7%
Controls	0.5%	1.5%	0.7%	0.8%	0.1%	1.8%	1.4%
Performance	1.2%	10.3%	4.4%	2.7%	0.1%	1.0%	1.4%
Miscellaneous (Steam Turbine)	6.0%	0.0%	0.0%	0.0%	0.0%	1.4%	1.4%
Miscellaneous	8.5%	11.8%	0.2%	0.1%	0.0%	0.3%	1.4%
Feedwater System	1.0%	0.0%	0.0%	0.0%	0.0%	1.8%	1.4%
Miscellaneous (Generator)	10.4%	1.0%	0.0%	1.2%	0.0%	0.7%	1.3%
All Other Causes	30.9%	33.8%	76.0%	28.9%	12.3%	17.5%	18.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-14 Contribution to EFOF by unit type: January through August 2009 (See 2008 SOM Table 5-23)

	EFOF	Contribution to EFOF
Combined Cycle	2.7%	7.0%
Combustion Turbine	1.6%	5.2%
Diesel	7.8%	0.3%
Hydroelectric	2.2%	1.8%
Nuclear	4.1%	15.7%
Steam	7.1%	69.9%
Total	4.9%	100.0%

Outages Deemed Outside Management Control

Table 5-15 PJM EFORd vs. XEFORd by unit type: January through August 2009 (See 2008 SOM Table 5-24)

	EFORd	XEFORd	Difference
Combined Cycle	3.7%	3.5%	0.2%
Combustion Turbine	8.8%	7.6%	1.2%
Diesel	9.7%	8.2%	1.5%
Hydroelectric	2.8%	2.6%	0.1%
Nuclear	4.2%	4.1%	0.0%
Steam	9.6%	8.3%	1.3%
Total	7.4%	6.6%	0.8%

Components of EFORp

Table 5-16 Contribution to EFORp by unit type (Percentage points): Calendar years 2008 to 2009 (January through August) (New Table)

	2008	2009 (Jan - Aug)
Combined Cycle	0.3	0.3
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.1	0.1
Nuclear	0.2	0.8
Steam	3.9	2.2
Total	4.9	3.8

Table 5-17 PJM EFORp data by unit type: Calendar years 2008 to 2009 (January through August) (New Table)

	2008	2009 (Jan - Aug)
Combined Cycle	2.4%	2.1%
Combustion Turbine	3.0%	2.4%
Diesel	5.3%	4.9%
Hydroelectric	1.7%	2.9%
Nuclear	0.8%	4.1%
Steam	7.9%	4.6%
Total	4.9%	3.8%

EFORd and EFORp

Table 5-18 Contribution to PJM EFORd and EFORp by unit type: Calendar year 2009 (January through August) (New Table)

	EFORd	EFORp	Difference
Combined Cycle	0.5	0.3	0.2
Combustion Turbine	1.4	0.4	1.0
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	(0.0)
Nuclear	0.8	0.8	0.0
Steam	4.6	2.2	2.4
Total	7.4	3.8	3.6

Table 5-19 PJM EFORd and EFORp data by unit type: Calendar year 2009 (January through August) (New Table)

	EFORd	EFORp	Difference
Combined Cycle	3.7%	2.1%	1.6%
Combustion Turbine	8.8%	2.4%	6.4%
Diesel	9.7%	4.9%	4.8%
Hydroelectric	2.8%	2.9%	(0.2%)
Nuclear	4.2%	4.1%	0.1%
Steam	9.6%	4.6%	5.0%
Total	7.4%	3.8%	3.6%

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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.

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 the 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.

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.

1 75 FERC ¶ 61,080 (1996).
2 Regulation is used to help control the area control error (ACE). See *2008 State of the Market Report,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2008.
3 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

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.

PJM does not provide a market for black start services, which are procured and paid zonally, but does review the adequacy of black start resources.

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 from January through September 2009.

Overview

Regulation Market

The PJM Regulation Market in 2009 continues to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented changes to the Regulation Market including the introduction of the three pivotal supplier test for market power, a change to the calculation of lost opportunity cost (LOC) and a change to the treatment of regulation revenues with respect to operating reserve credits. The MMU will provide a report to FERC on November 26, 2009 on the impact of these changes.

Market Structure

- **Supply.** During the first nine months of 2009, 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 2009. The ratio of eligible regulation offered to regulation required averaged 2.98 throughout the first nine months of 2009, an increase from the 2008 ratio.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. Previously the requirement had been fixed daily at 1.0 percent of the daily forecast operating load. The average hourly regulation demand in the first nine months of 2009 was 863 MW, compared to 947 MW for the first nine months of 2008.

- **Market Concentration.** During the first nine months of 2009, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1290 which is classified as "moderately concentrated."[4] The minimum hourly HHI was 699 and the maximum hourly HHI was 7551. The largest hourly market share in any single hour was 86 percent, and 66 percent of all hours had a maximum market share greater than 20 percent.

  The high hourly HHIs resulted from an increase in high maximum market share hours during early morning off-peak hours in July, August, and September. An increase in self scheduled regulation reduced the amount of regulation procured from the market. This appears to be related to PJM changes to the calculation of LOC, which resulted in higher off-peak clearing prices. In the first nine months of 2009, 46 percent of hours had one or more pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market in the first nine months of 2009 was characterized by structural market power in 46 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner, and PJM adds LOC calculated using LMP forecasts, which together comprise the total offer to the Regulation Market for each unit. Beginning December 1, 2008 PJM implemented a three pivotal supplier test in the regulation market. As part of the implementation, owners are required to submit unit specific cost based offers which may include up to a $12 per MWh margin adder, and owners have the option to submit price based offers. All offers remain subject to the $100 per MWh cap. All units of owners who fail the three pivotal supplier test for an hour are offered at the lesser of their cost based or price based offer. As part of the changes to the regulation market implemented on December 1, 2008, PJM no longer nets regulation revenue against operating reserve revenue and PJM calculates lost opportunity costs using the lower of cost based or price based offers as the reference rather than the offer on which the unit is operating.

4 See the *2008 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.** For the PJM Regulation Market during the first nine months of 2009 the load weighted, average price per MWh (the regulation market clearing price, including lost opportunity cost) associated with meeting PJM's demand for regulation was $24.99. This is a significant reduction from the $45.40 average load weighted price for January through September of 2008.

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 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 south 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 LOC payments and aligned the total cost of synchronized reserves with Synchronized Reserve Market prices. Synchronized reserves added out of market were less than three percent of all synchronized reserve during April through September of 2009 while they were 47 percent for the same

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time period in 2008. LOC accounted for 23 percent of total costs during April through August of 2009 compared to 55 percent during the same time period in 2008.

Market Structure

- **Supply.** For the period January through September 2009, the offered and eligible excess supply ratio was 1.38 for the PJM Mid-Atlantic Synchronized Reserve Region.[5] 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 2009, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,360 MW for the RFC Synchronized Reserve Zone and 1,170 MW for the Mid-Atlantic Subzone. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared.

  Demand for synchronized reserve in the Mid-Atlantic subzone increased substantially during September as a result of three consecutive days (September 14, 15, and 16) of double spinning requirements. 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. In the Southern Synchronized Reserve Zone only six hours cleared a Tier 2 market in 2009. In the PJM Mid-Atlantic Synchronized Reserve Region, 67 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 300 MW.

  The problem of additional procurement of Tier 2 synchronized reserves by PJM dispatch after Synchronized Reserve Market settlement has been greatly reduced. For January through September 2009, 19 percent of all purchased Tier 2 synchronized reserves were added after the market cleared. Most of the added synchronized reserve occurred in the January through March period. From April through September 2009 less than three percent of all purchased Tier 2 synchronized reserves were added after the market cleared.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for January through September 2009 was 2765. For purchased synchronized reserve (cleared plus added) the HHI was 3393. Less than one percent of all hours had a market share of 100 percent. In 41 percent of hours the maximum market share was greater than 40 percent (compared to 56 percent of hours in 2008). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for the period January through September 2009, 93 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2009 are characterized by structural market power.

Market Conduct

- **Offers.** Daily offer prices are submitted for each unit by the unit owner, and PJM adds LOC 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.

Market Performance

- **Price.** During January and to a lesser extent February, only a very small amount of Tier 2 was needed, which resulted in lower clearing prices. The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $7.55 per MW for January through September 2009, a $3.32 per MW decrease from January through September 2008.

- **Demand.** Demand for Tier 2 synchronized reserve was varied substantially during the first quarter of 2009 as a result of PJM changes to the definition of the market. On December 1, 2008 PJM began to significantly increase the amount of Tier 1 forecast during the market solution, which reduced the demand for Tier 2 in January and February 2009. On March 13, 2009 PJM reduced the amount of Tier 1 from outside the Mid-Atlantic subzone that is included for the operational hour, which increased demand for Tier 2. Demand side resources

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

remained significant participants in the Synchronized Reserve Market from January through September 2009. In 18 percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by DSR.

- **Availability.** 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 January through September 2009.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[6] 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 annually by the reliability region.[7] 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 reserves, PJM is required to schedule additional operating reserves.

Market Structure

The DASR Market from January through September 2009 had three pivotal suppliers in a monthly average of 32 percent of all hours. The MMU concludes from these results that the PJM DASR Market in the first nine months of 2009 was characterized by structural market power.

Market Conduct

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. In September, almost six percent of units offered at $50 or more and four percent of units offered at $990 or more, in a market with an average clearing price of $0.05 and a maximum clearing price of $1.00.

6 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
7 PJM Manual 13, Emergency Requirements, Rev 38, 10/05/2009; pp 11-12.

Market Performance

For January through September, 2009, the load weighted price of DASR was $0.05, including the almost 40 percent of hours when the market cleared at a price of $0.00. Demand side resources do participate in the DASR market but remain insignificant.

Black Start Services

Black Start Service is necessary to help ensure the reliable restoration of the grid following a black out. 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.[8]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

PJM does not have a market to provide black start service, but compensates black start resource owners for all costs associated with providing this service, as defined in the tariff. For 2008, charges to PJM members for providing black start services were just over $13 million. For the first nine months of 2009, charges were about $9.2 million.

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.

8 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.

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Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU has consistently found since that time that the PJM Regulation Market is characterized by structural market power during a significant number of hours. This conclusion is based on the results of the three pivotal supplier test.

In 2008, PJM and its stakeholders addressed the issue of market power mitigation for the Regulation Market in the Three Pivotal Supplier Task Force (TPSTF), which was convened pursuant to PJM's 2007 Strategic Report to review market power mitigation issues.[9] The TPSTF achieved a consensus supporting the application of the three pivotal supplier (TPS) test to the Regulation Market, provided that three adjustments to the rules were included, all of which increased margins for regulation units. PJM filed the proposed revisions on October 1, 2008.[10] A number of parties filed comments, including the MMU on October 20, 2008.[11] The MMU supported the consensus but requested that the Commission direct the MMU to report on the three adjustments to the rules: increasing the current $7.50 adder to cost based offers to $12; modifying the calculation of opportunity costs to use the lower of cost based or price based offers as the reference; and eliminating the netting of revenues from the Regulation Market from make whole balancing operating reserve payments. The Commission, in accepting PJM's filing on November 26, 2008, directed the Market Monitoring Unit to prepare a report due on November 26, 2009.[12]

On December 1, 2008, the three pivotal supplier test was implemented in the Regulation Market to address the identified market power problems. As a result, the Regulation Market results in the first half of 2009 were competitive.

The MMU also concludes that the other changes to the Regulation Market implemented on December 1, 2008 significantly increased the price of regulation compared to what prices would have been absent those changes. The MMU will provide an updated analysis of results and associated recommendations to FERC, due November 26, 2009.

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 concludes that the DASR Market is not structurally competitive in a significant number of hours based on the results of the three pivotal supplier test. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU also concludes that the DASR Market results were competitive in the first half of 2009.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

Overall, the MMU concludes that the Regulation Market results were competitive in the first three quarters of 2009. The MMU concludes that the Synchronized Reserve Market results were competitive in the first three quarters of 2009. The MMU concludes that the DASR Market results were competitive in the first three quarters of 2009.

9 See PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's Website at: http://www2.pjm.com/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.pdf.

10 PJM submitted its initial filing in FERC Docket No. ER09-13-000.

11 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000. These comments are posted on the Monitoring Analytics website at http://www.monitoringanalytics.com.

12 *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,231, at P 18 (2008).

Regulation Market

Market Structure

Table 6-1 PJM Regulation Market Required MW and Ratio of Supply to Requirement: January through September 2009 (See 2008 SOM Table 6-1)

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
2009 (Jan - Sep)	863	2.98
Fall	802	3.27
Spring	771	2.89
Summer	929	3.14
Winter	938	2.74
Off-Peak	784	2.90
On-Peak	951	3.07

Market Concentration

Table 6-2 PJM regulation capability, daily offer and hourly eligible: January through September 2009 (See 2008 SOM Table 6-2)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percentage of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,629	6,313	83%	2,563	34%
Off Peak	7,629			2,236	29%
On Peak	7,629			2,925	38%

Table 6-3 PJM cleared regulation HHI: January through September 2009 (See 2008 SOM Table 6-3)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, 2009	699	1290	7551

Figure 6-1 PJM Regulation Market HHI distribution: January through September 2009 (See 2008 SOM Figure 6-1)

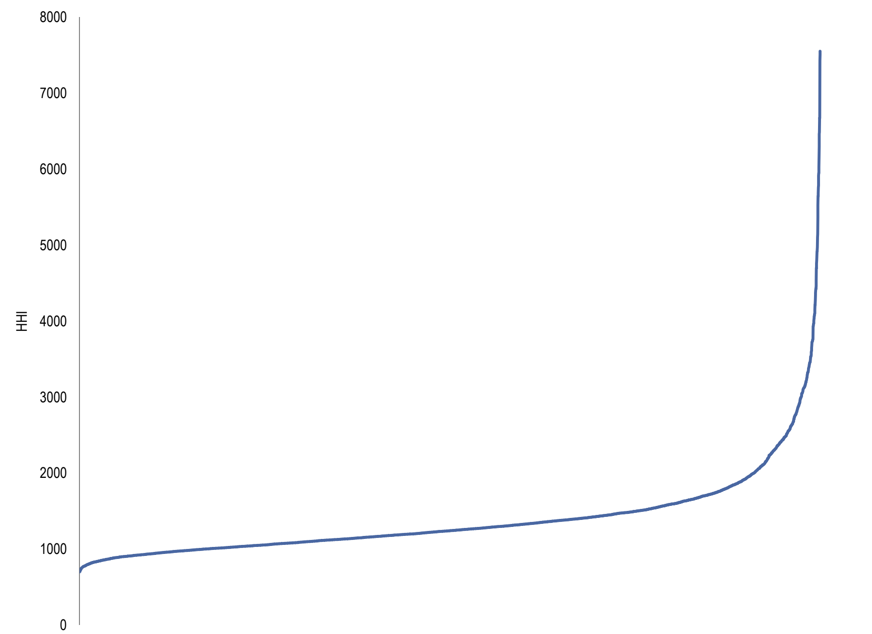

Table 6-4 Highest annual average hourly Regulation Market shares: January through September 2009 (See 2008 SOM Table 6-4)

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

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Table 6-5 Regulation market monthly three pivotal supplier results: January through September 2009 (See 2008 SOM Table 6-5)

Month	Percent of Hours With Three Pivotal Suppliers
Jan	84%
Feb	61%
Mar	42%
Apr	40%
May	31%
Jun	37%
Jul	39%
Aug	35%
Sep	47%

Market Performance

Price

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MWh): January through September 2009 (See 2008 SOM Figure 6-2)

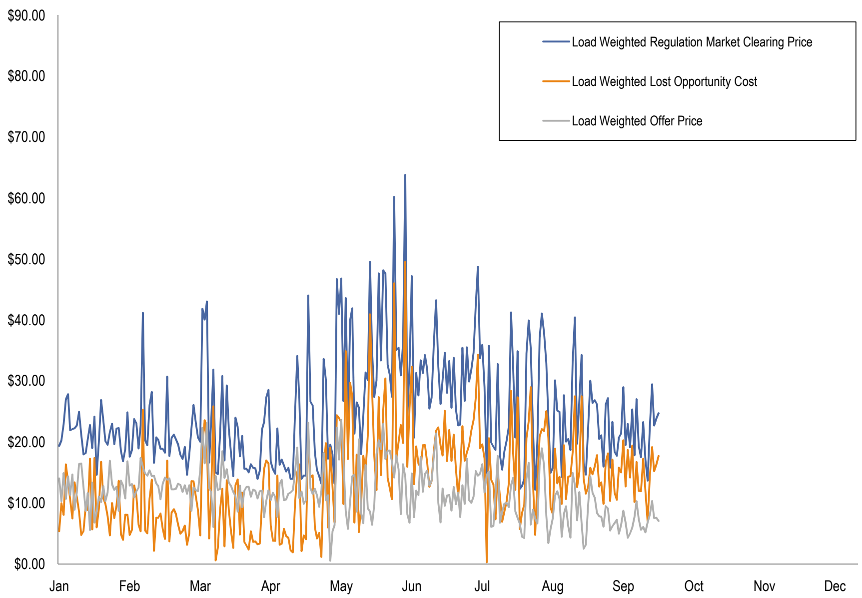


Figure 6-3 Monthly average regulation demand (required) vs. price: January through September 2009 (See 2008 SOM Figure 6-3)

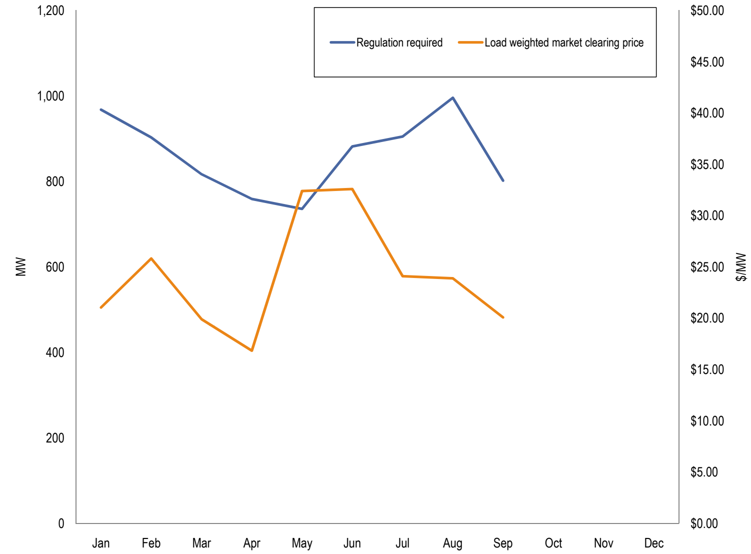


Figure 6-4 Monthly load weighted, average regulation cost and price: January through September 2009 (See 2008 SOM Figure 6-4)

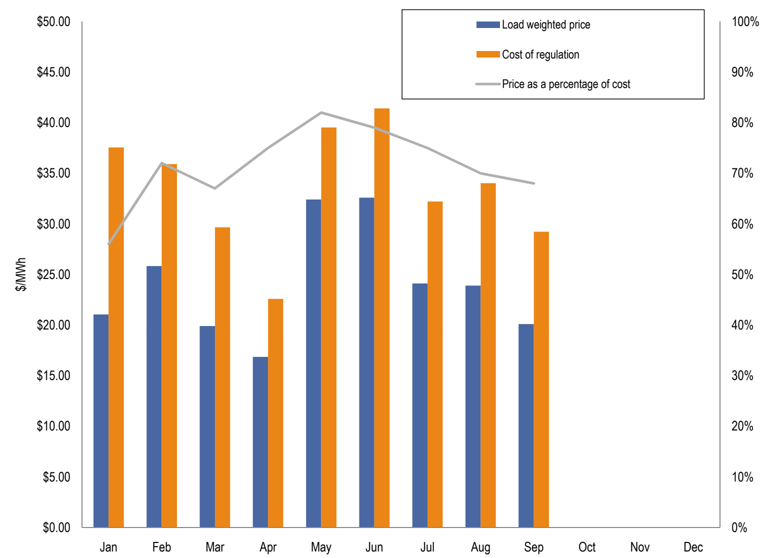


Table 6-6 Total regulation charges: January through September 2009 (See 2008 SOM Table 6-6)

Month	Total Purchased Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price	Regulation Cost (per MW Regulation)
Jan	708,801	$26,614,050	$21.04	$37.55
Feb	597,418	$21,455,212	$25.83	$35.91
Mar	601,980	$17,853,025	$19.90	$29.66
Apr	538,993	$12,172,449	$16.84	$22.58
May	535,862	$21,180,526	$32.41	$39.53
Jun	595,554	$24,664,652	$32.59	$41.41
Jul	628,265	$20,237,959	$24.10	$32.21
Aug	677,555	$23,049,672	$23.89	$34.02
Sep	521,875	$15,251,640	$20.09	$29.22

Synchronized Reserve Market

Figure 6-5 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through September 2009 (See 2008 SOM Figure 6-5)

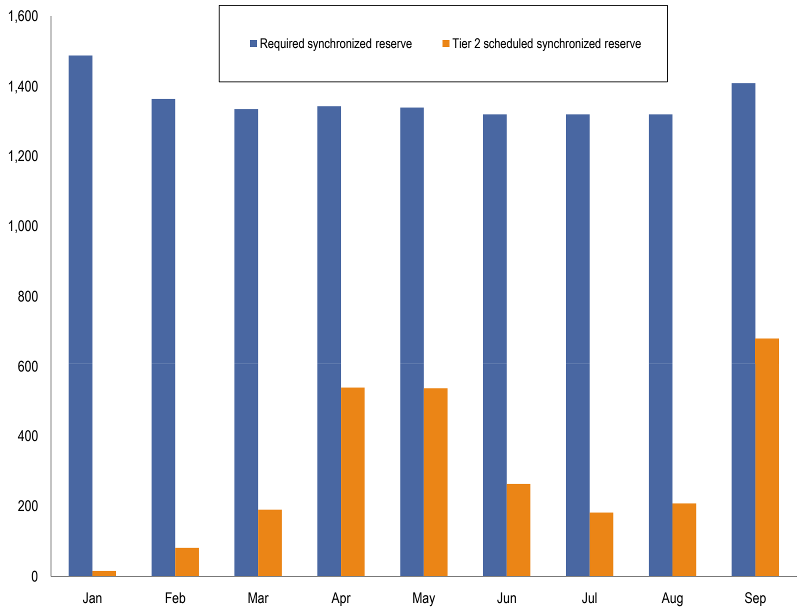
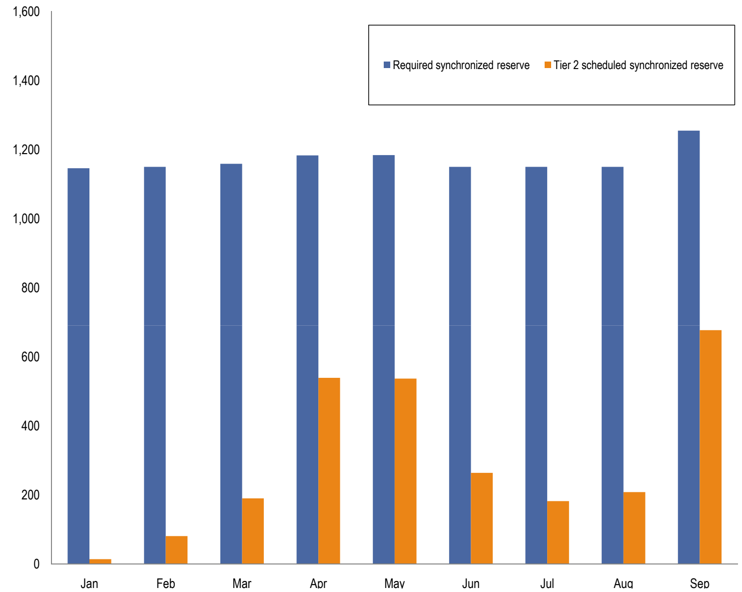
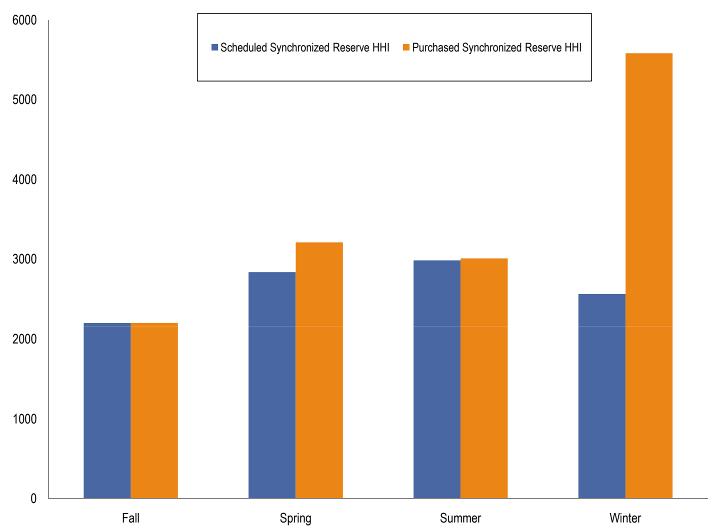


Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through September 2009 (See 2008 SOM Figure 6-6)



Market Concentration

Figure 6-7 Cleared Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: January through September 2009 (See 2008 SOM Figure 6-7)



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Market Conduct

Offers

Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): January through September 2009 (See 2008 SOM Figure 6-8)

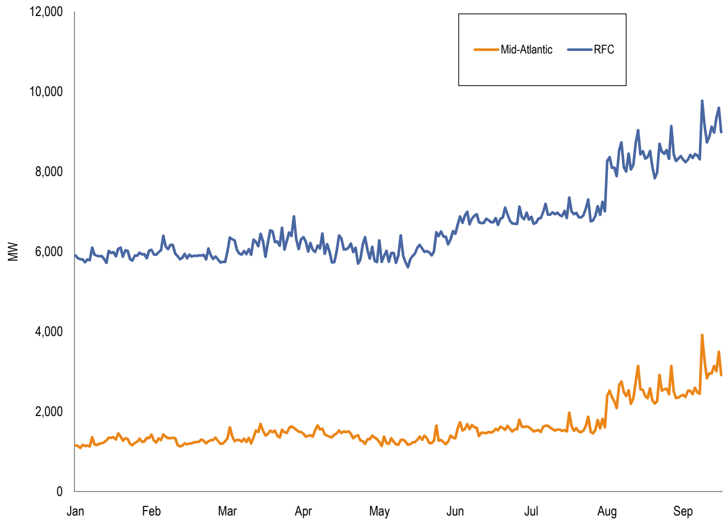
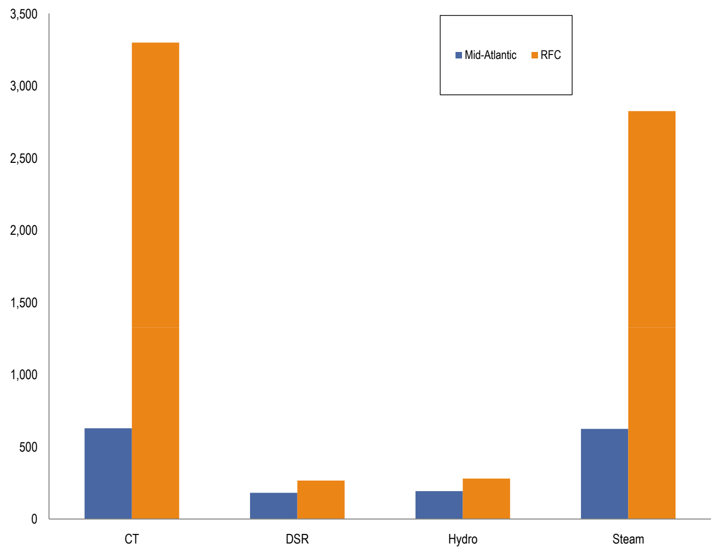


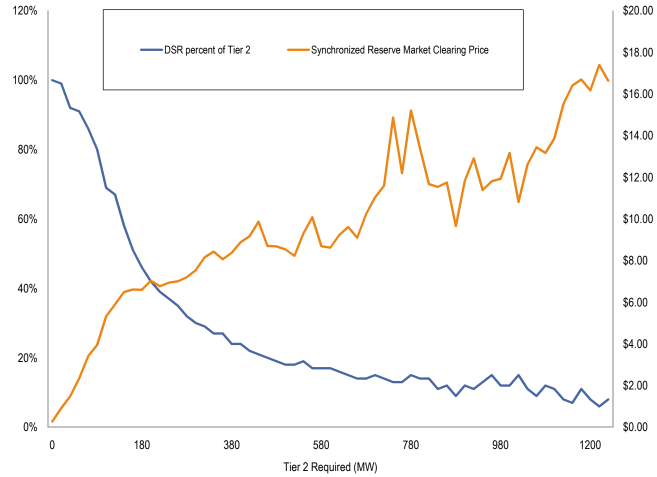
Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through September 2009 (See 2008 SOM Figure 6-9)



Market Performance

Price

Figure 6-10 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2: January through September 2009 (See 2008 SOM Figure 6-10)



Price and Cost

Figure 6-11 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 2009 (See 2008 SOM Figure 6-11)

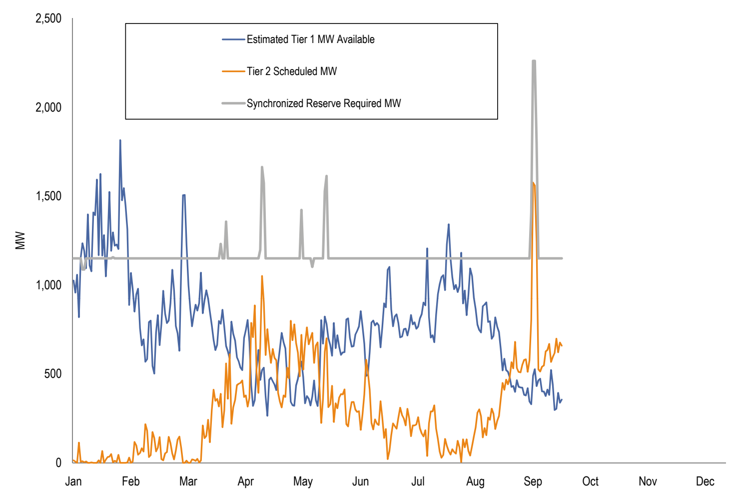


Figure 6-12 Synchronized reserve purchases by month; PJM scheduled, self-scheduled, and added: January through September 2009 (See 2008 SOM Figure 6-12)

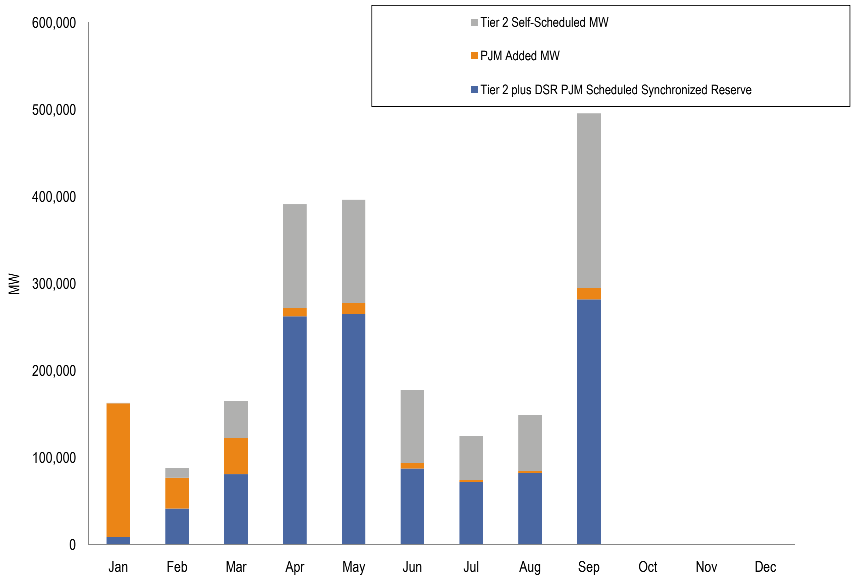


Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic subzone: January through September 2009 (See 2008 SOM Figure 6-13)

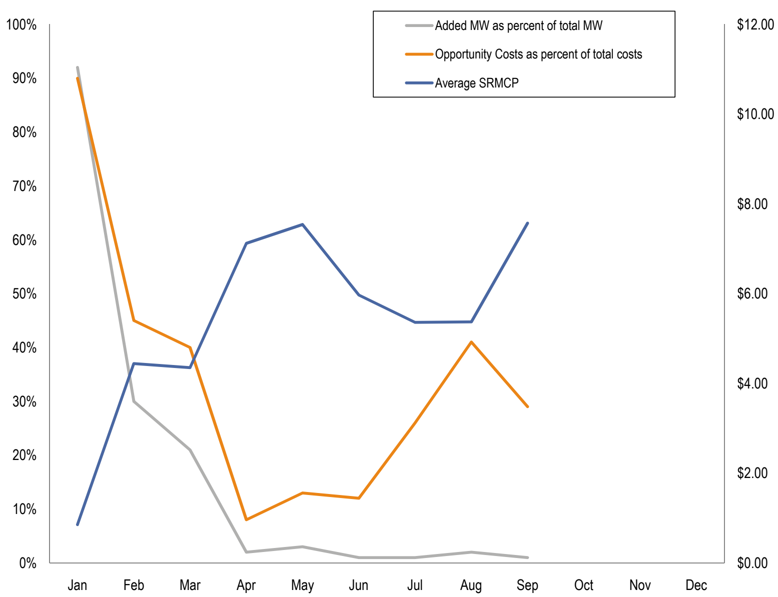
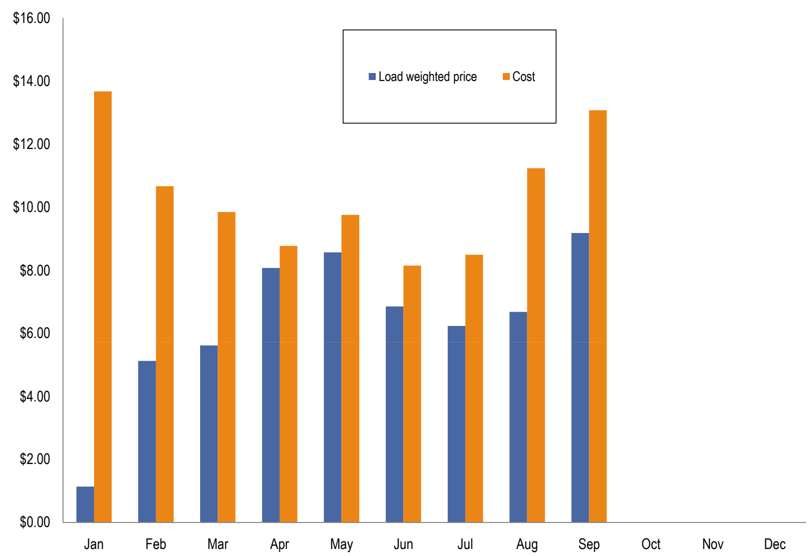


Figure 6-14 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): January through September 2009 (See 2008 SOM Figure 6-14)



Market Solution and Actual Dispatch of Ancillary Services

DSR

Table 6-7 Average SRMCP when all cleared synchronized reserve is DSR: January through September 2009 (See 2008 SOM Table 6-8)

Month	Average SRMCP when all cleared synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$1.24	$5.90	43%
Feb	$2.01	$5.09	47%
Mar	$1.98	$5.50	26%
Apr	$2.49	$7.12	9%
May	$1.91	$7.56	12%
Jun	$1.76	$5.97	27%
Jul	$1.95	$5.41	31%
Aug	$1.36	$5.37	13%
Sep	$1.77	$7.65	2%

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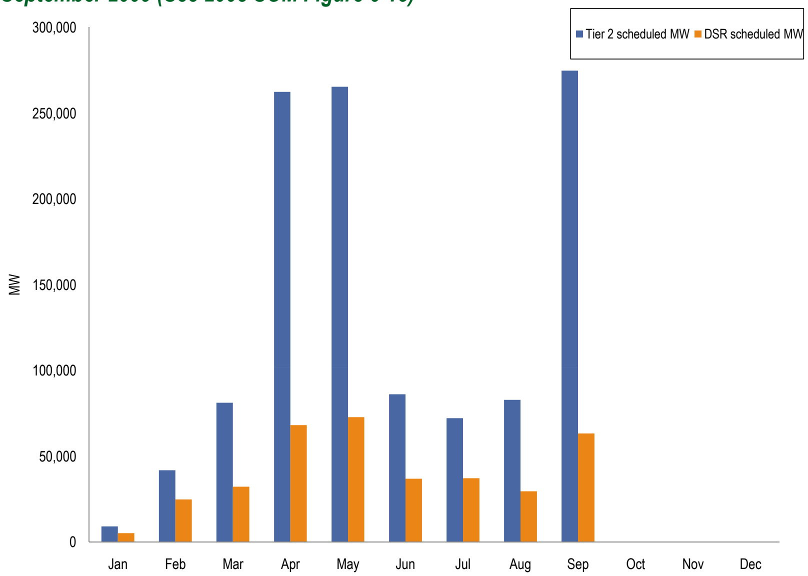
Figure 6-15 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through September 2009 (See 2008 SOM Figure 6-15)



Availability

Day Ahead Scheduling Reserve (DASR)

Table 6-8 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September 2009 (See 2008 SOM Table 6-9)

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	5,875	$0.00	$0.50	$0.09	4,103,463	$381,735
Feb	5,517	$0.00	$0.25	$0.05	3,510,983	$180,767
Mar	5,068	$0.00	$1.00	$0.03	3,499,722	$113,507
Apr	4,910	$0.00	$0.50	$0.03	3,354,999	$92,158
May	4,957	$0.00	$0.07	$0.02	3,478,374	$77,850
Jun	5,936	$0.00	$0.75	$0.05	4,006,547	$191,578
Jul	6,071	$0.00	$0.50	$0.04	4,191,307	$155,790
Aug	6,725	$0.00	$4.00	$0.13	4,773,330	$620,430
Sep	5,438	$0.00	$0.42	$0.02	3,764,923	$77,945

Table 6-9 2008 PJM, Day-Ahead Scheduling Reserve Market pivotal supplier results: January through September 2009 (See 2008 SOM Table 6-10)

Month	Percentage of Hours With Three Pivotal Suppliers
Jan	15%
Feb	61%
Mar	76%
Apr	55%
May	48%
Jun	5%
Jul	3%
Aug	21%
Sep	0%

Black Start Service

Table 6-10 Black Start yearly zonal charges for network transmission use: January through September 2009 (See 2008 SOM Table 6-11)

Zone	Network Charges
AECO	$313,486
AEP	$548,359
AP	$101,432
BGE	$359,347
ComEd	$5,078,367
DAY	$109,013
DPL	$264,246
DLCO	$19,890
JCPL	$325,524
Met-Ed	$302,662
PECO	$539,893
PENELEC	$250,272
Pepco	$166,311
PPL	$92,933
PSEG	$706,225

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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 to some loads. 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 2009.

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 *2008 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.** During the first nine months of 2009, total congestion costs decreased by $1.235 billion or 69 percent, from $1.778 billion to $543.6 million. Day-ahead congestion costs decreased by $1.546 billion or 69 percent, from $2.251 billion during the first nine months of 2008 to $704.6 million during the first nine months of 2009. Balancing congestion costs increased by $311.7 million or 63 percent, from -$472.7 million during the first nine months of 2008 to -$161.0 during the first nine months of 2009. Total congestion costs have ranged from six percent to nine percent of PJM annual total billings since 2003. Congestion costs were three percent of total PJM billings for the first nine months of 2009. Total PJM billings for the first nine months of 2009 were $13.457 billion, an 18 percent decrease from the $16.369 billion billed during the first nine months of 2008.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. During the first nine months of 2009, 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.

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. This 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.** As was the case in 2008, congestion frequency has been significantly higher in the Day-Ahead Market than in the Real-Time Market in 2009.[3] Day-ahead congestion frequency increased during the first nine months of 2009 compared to the first nine months of 2008. During the first nine months of 2009, there were 59,290 day-ahead, congestion-event hours compared to 57,661 day-ahead congestion-event hours during the first nine months of 2008. Day-ahead, congestion-event hours increased on PJM transmission lines and the reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) while congestion frequency on internal PJM interfaces and transformers decreased. Real-time congestion frequency decreased during the first nine months of 2009 compared to the first nine months of 2008. During the first nine months of 2009, there were 17,641 real-time, congestion-event hours compared to 12,640 real-time congestion-event hours during the first nine months of 2008. Real-time, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and the Midwest ISO, while interfaces, transmission lines and transformers saw decreases. The AP South Interface was the largest contributor to congestion costs during the first nine months of 2009. With $149.1 million in total congestion costs, it accounted for 27 percent of the total PJM congestion costs during the first nine months of 2009. The top five constraints in terms of congestion costs together contributed $285 million, or 52 percent, of the total PJM congestion costs during the first nine months of 2009. The top five constraints included the AP South Interface, the West Interface, the 5004/5005 Interface, ,the Kammer transformer and the East Frankfort - Crete line.

- **Zonal Congestion.** During the first nine months of 2009, the ComEd Control Zone experienced the highest congestion costs of the control zones in PJM. However, during the first nine months of 2009, the average congestion component of LMP in ComEd was -$5.61 and -$6.24 for day-ahead and real-time, respectively. The negative congestion components in ComEd resulted in -$212.2 million in load congestion payments, -$384.3 million in generation congestion credits, and -$4.0 in explicit congestion charges. The net positive congestion number in ComEd is an example of how accounting congestion can be a misleading measure of congestion when it results from generation congestion credits which are more negative than load congestion payments. In fact, congestion reduces prices in ComEd, and as a result, load incurs lower charges and generation receives lower credits. The $123.1 million in net congestion costs in the ComEd Control Zone represented a 10.4 percent decrease from the $168.1 million in congestion costs the zone had experienced during the first six months of 2008. The Pleasant Valley – Belvidere line, the Dunes Acres – Michigan City flowgate, the Kammer transformer, the East Frankfort – Crete line, and the AP South interface contributed $90.5 million, or 54 percent of the total ComEd Control Zone congestion costs (Table 7-44). The Dominion Control Zone had the second highest congestion cost in PJM during the first nine months of 2009. The $77.4 million in congestion costs in the Dominion Control Zone represented a 72 percent decrease from the $272.6 million in congestion costs the zone had experienced during the first nine months of 2008. The AP South Interface contributed $47.7 million, or 62 percent of the total Dominion Control Zone congestion cost.

Conclusion

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. Total congestion costs decreased by $1.235 billion or 69 percent, from $1.778 billion to $543.6 million. Day-ahead congestion costs decreased by $1.546 billion or 69 percent, from $2.251 billion during the first nine months of 2008 to $704.6 million during the first nine months of 2009. Balancing congestion costs increased by $311.7 million or 63 percent, from -$472.7 million during the first nine months of 2008 to -$161.0 during the first nine months of 2009. Congestion costs were significantly higher in the Day-Ahead Market than in the balancing market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. During the first nine months of 2009, there were 59,290 day-ahead, congestion-event hours compared to 57,661 congestion-event hours during the first nine months of 2008. During the first nine months of 2009, there were 17,641 real-time, congestion-event hours compared to 12,640 real-time congestion-event hours during the first nine months of 2008.

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 first

3 Prior state of the market reports measured real-time congestion frequency using the convention that a congestion-event hour exists if the particular facility is constrained for four or more of the 12 five-minute intervals comprising that hour. In the *2008 State of the Market Report for PJM*, 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. Comparisons to previous periods use the new standard for both current and prior periods.

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four months of the 2009 to 2010 planning period, ARR and FTR revenue hedged 92.1 percent of the total congestion costs within PJM.[4] FTRs were paid at 100 percent of the target allocation for the planning year ended May 31, 2009 and 96 percent of the target allocation level for the first four months of the 2009 to 2010 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 3.5 percent of total energy charges to load for the first three quarters of 2009. FTRs acquired through FTR auctions had a net negative value, probably largely as a result of lower than expected congestion.

One constraint accounted for over a quarter of total congestion costs during the first nine months of 2009 and the top five constraints accounted for more than half of total congestion costs. The AP South interface was the largest contributor to congestion costs during the first nine months of 2009.

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.[5] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits 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 during the first nine months of 2009 in PJM was $543.6 million, which was comprised of load congestion payments of $210.6 million, negative generation credits of $380.9 million and negative explicit congestion of $48.0 million (see Table 7-2).

Congestion

Congestion Accounting

Total Calendar Year Congestion

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to September 2009 (See 2008 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	$544	NA	$19,932	3%
Total	$9,415		$143,969	7%

4 See the *2008 State of the Market Report for PJM*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-28, "ARR and FTR congestion hedging: Planning periods 2007 to 2008 and 2008 to 2009."

5 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.

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through September 2008 and 2009 (New Table)

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2008 (Jan-Sep)	$921.9	($880.7)	($24.5)	$1,778.2
2009 (Jan-Sep)	$210.6	($380.9)	($48.0)	$543.6

Monthly Congestion

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): January through September 2008 and 2009 (See 2008 SOM Table 7-2)

	2008	2009	Change
Jan	$231.0	$149.3	($81.7)
Feb	$168.1	$83.0	($85.2)
Mar	$86.4	$74.6	($11.8)
Apr	$126.2	$25.6	($100.6)
May	$182.8	$25.9	($157.0)
Jun	$371.5	$49.8	($321.7)
Jul	$359.9	$39.4	($320.5)
Aug	$127.4	$72.1	($55.3)
Sep	$124.8	$23.9	($100.9)
2009 (Jan - Sep)	$1,778.2	$543.6	($1,234.6)

Congestion Component of LMP

Table 7-4 Annual average congestion component of LMP: January through September 2008 and 2009 (See 2008 SOM Table 7-3)

	2008 (Jan - Sep)		2009 (Jan - Sep)	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$9.05	$12.91	$2.35	$2.13
AEP	($11.24)	($12.66)	($2.24)	($2.32)
AP	($0.47)	($0.04)	$0.83	$1.62
BGE	$12.50	$12.82	$3.24	$3.05
ComEd	($12.82)	($15.07)	($5.61)	($6.24)
DAY	($11.68)	($13.36)	($3.01)	($2.99)
DLCO	($12.84)	($16.33)	($3.73)	($3.53)
Dominion	$9.51	$10.47	$2.59	$2.60
DPL	$8.60	$8.88	$2.58	$2.67
JCPL	$9.18	$10.32	$2.07	$2.11
Met-Ed	$7.39	$7.44	$2.33	$2.21
PECO	$6.46	$6.78	$2.10	$1.88
PENELEC	($1.22)	($3.27)	$0.01	($0.04)
Pepco	$14.06	$14.16	$3.78	$3.82
PPL	$6.23	$6.20	$2.12	$1.90
PSEG	$8.84	$10.35	$2.45	$2.53
RECO	$7.62	$8.90	$1.69	$1.73

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Congested Facilities

Congestion by Facility Type and Voltage

Table 7-5 Congestion summary (By facility type): January through September 2009 (See 2008 SOM Table 7-4)

	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	($40.8)	$15.1	$72.7	($10.6)	$3.4	($59.8)	($73.8)	($1.1)	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	($154.4)	$36.0	$287.5	($16.4)	$8.1	($33.4)	($57.8)	$229.7	40,152	6,145
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	59,290	12,640

Table 7-6 Congestion summary (By facility type): January through September 2008 (See 2008 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	$6.8	($9.5)	$7.3	$23.5	($4.1)	$4.6	($29.5)	($38.2)	($14.6)	1,709	1,212
Interface	$324.6	($463.0)	$34.7	$822.3	($18.2)	$22.1	($11.8)	($52.1)	$770.2	6,378	1,780
Line	$516.0	($353.7)	$83.9	$953.7	($113.0)	$33.4	($111.5)	($257.9)	$695.9	38,866	10,763
Transformer	$270.1	($135.7)	$25.3	$431.1	($69.7)	$30.4	($24.5)	($124.5)	$306.5	10,708	3,886
Unclassified	$9.4	($9.3)	$1.6	$20.3	$0.0	$0.0	$0.0	$0.0	$20.3	NA	NA
Total	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$1,778.2	57,661	17,641

Table 7-7 Congestion summary (By facility voltage): January through September 2009 (See 2008 SOM Table 7-6)

	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	6,072	1,793
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	22,256	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
Unclassified	$0.2	$0.2	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	NA	NA
Total	$243.0	($391.3)	$74.2	$708.5	($35.1)	$4.1	($121.9)	($161.0)	$547.5	58,650	12,640

Table 7-8 Congestion summary (By facility voltage): January through September 2008 (See 2008 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	$1.6	($3.0)	$0.1	$4.7	$1.4	$0.6	($0.0)	$0.7	$5.4	83	21
500	$639.5	($703.5)	$71.9	$1,415.0	($95.9)	$6.3	($34.8)	($137.0)	$1,278.0	14,175	5,883
345	$35.6	($38.4)	$24.0	$98.0	($27.2)	$12.4	($88.7)	($128.3)	($30.3)	3,114	1,628
230	$186.9	($106.2)	$24.7	$317.8	($32.4)	$49.1	($19.2)	($100.7)	$217.0	11,579	3,391
138	$166.0	($105.3)	$29.1	$300.4	($32.7)	$9.8	($29.7)	($72.2)	$228.2	16,328	4,890
115	$53.8	($8.4)	$1.0	$63.2	($15.8)	$10.5	($4.6)	($30.9)	$32.3	6,874	1,251
69	$34.2	$3.0	$0.3	$31.6	($2.3)	$1.8	($0.2)	($4.3)	$27.3	5,508	553
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	24
12	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Unclassified	$9.4	($9.3)	$1.6	$20.3	$0.0	$0.0	$0.0	$0.0	$20.3	NA	NA
Total	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$1,778.2	57,661	17,641

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Constraint Duration

Table 7-9 Top 25 constraints with frequent occurrence: January through September 2008 and 2009 (See 2008 SOM Table 7-8)[6]

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2008	2009	Change	2008	2009	Change	2008	2009	Change	2008	2009	Change
1	Cloverdale - Lexington	Line	2,941	752	(2,189)	1,506	335	(1,171)	45%	11%	(33%)	23%	5%	(18%)
2	Dunes Acres - Michigan City	Flowgate	310	2,888	2,578	263	907	644	5%	44%	39%	4%	14%	10%
3	Leonia - New Milford	Line	422	3,088	2,666	48	39	(9)	6%	47%	41%	1%	1%	(0%)
4	Pleasant Valley - Belvidere	Line	0	2,342	2,342	15	266	251	0%	36%	36%	0%	4%	4%
5	Burlington - Croydon	Line	256	2,420	2,164	5	3	(2)	4%	37%	33%	0%	0%	(0%)
6	Mount Storm - Pruntytown	Line	1,546	525	(1,021)	771	132	(639)	24%	8%	(16%)	12%	2%	(10%)
7	Trainer - Delco Tap	Line	1,658	0	(1,658)	0	0	0	25%	0%	(25%)	0%	0%	0%
8	Atlantic - Larrabee	Line	1,501	188	(1,313)	368	45	(323)	23%	3%	(20%)	6%	1%	(5%)
9	Pinehill - Stratford	Line	2,613	1,020	(1,593)	0	0	0	40%	16%	(24%)	0%	0%	0%
10	Kammer	Transformer	2,251	3,674	1,423	1,261	1,328	67	34%	56%	22%	19%	20%	1%
11	Tiltonsville - Windsor	Line	0	1,258	1,258	5	237	232	0%	19%	19%	0%	4%	4%
12	Branchburg - Readington	Line	1,117	21	(1,096)	271	10	(261)	17%	0%	(17%)	4%	0%	(4%)
13	Mount Storm	Transformer	908	123	(785)	460	70	(390)	14%	2%	(12%)	7%	1%	(6%)
14	Oak Grove - Galesburg	Flowgate	0	645	645	4	531	527	0%	10%	10%	0%	8%	8%
15	Waterman - West Dekalb	Line	102	1,216	1,114	1	41	40	2%	19%	17%	0%	1%	1%
16	Bedington - Black Oak	Interface	1,361	395	(966)	209	61	(148)	21%	6%	(15%)	3%	1%	(2%)
17	East Towanda	Transformer	803	0	(803)	306	0	(306)	12%	0%	(12%)	5%	0%	(5%)
18	West	Interface	1,197	391	(806)	372	85	(287)	18%	6%	(12%)	6%	1%	(4%)
19	Athenia - Saddlebrook	Line	70	1,094	1,024	76	139	63	1%	17%	16%	1%	2%	1%
20	Kammer - Ormet	Line	0	552	552	0	509	509	0%	8%	8%	0%	8%	8%
21	Electric Jct - Nelson	Line	0	819	819	46	202	156	0%	13%	13%	1%	3%	2%
22	Ruth - Turner	Line	0	704	704	11	279	268	0%	11%	11%	0%	4%	4%
23	East Frankfort - Crete	Line	530	1,490	960	0	0	0	8%	23%	15%	0%	0%	0%
24	State Line - Wolf Lake	Flowgate	1,129	415	(714)	366	152	(214)	17%	6%	(11%)	6%	2%	(3%)
25	Meadow Brook	Transformer	774	50	(724)	173	0	(173)	12%	1%	(11%)	3%	0%	(3%)

6 Presented in descending order of absolute change between January through September 2008 and January through September 2009 day-ahead and real-time congestion-event hours.

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Constraint Costs

Table 7-10 Top 25 constraints affecting annual PJM congestion costs (By facility): January through September 2009 (See 2008 SOM Table 7-9)

				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	East Frankfort - Crete	Line	ComEd	$4.7	($12.8)	$7.4	$24.9	$0.0	$0.0	$0.0	$0.0	$24.9	5%
6	Pleasant Valley - Belvidere	Line	ComEd	($4.0)	($29.4)	$2.9	$28.3	$0.8	$1.9	($4.1)	($5.1)	$23.3	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%

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Table 7-11 Top 25 constraints affecting annual PJM congestion costs (By facility): January through September 2008 (See 2008 SOM Table 7-10)

				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	2008
1	AP South	Interface	500	$175.2	($283.1)	$17.5	$475.8	($12.1)	$7.1	($8.5)	($27.7)	$448.1	25%
2	Cloverdale - Lexington	Line	AEP	$143.3	($70.5)	$7.3	$221.1	($19.6)	($14.6)	($7.7)	($12.7)	$208.4	12%
3	Mount Storm - Pruntytown	Line	AP	$48.5	($122.2)	$12.1	$182.8	($21.8)	($15.4)	($2.8)	($9.3)	$173.5	10%
4	Bedington - Black Oak	Interface	500	$49.5	($99.9)	$6.5	$155.9	($1.0)	($0.3)	$0.7	($0.1)	$155.9	9%
5	West	Interface	500	$56.2	($33.8)	$6.0	$96.0	($1.9)	$8.3	($2.1)	($12.3)	$83.7	5%
6	Kammer	Transformer	500	$90.0	$20.4	$8.3	$77.8	($15.7)	($2.0)	$2.8	($10.9)	$67.0	4%
7	Sammis - Wylie Ridge	Line	AP	$9.1	($3.0)	$12.5	$24.6	($25.2)	$6.4	($57.1)	($88.7)	($64.2)	(4%)
8	Bedington	Transformer	AP	$19.5	($30.3)	$1.7	$51.5	($1.5)	($1.3)	($0.4)	($0.6)	$50.9	3%
9	Mount Storm	Transformer	AP	$22.0	($60.2)	$9.8	$92.0	($20.9)	$14.2	($15.8)	($50.9)	$41.1	2%
10	Atlantic - Larrabee	Line	JCPL	$40.6	($15.2)	$5.4	$61.2	($9.6)	$8.0	($4.7)	($22.3)	$39.0	2%
11	Meadow Brook	Transformer	AP	$21.8	($17.5)	$0.8	$40.1	($4.4)	($1.2)	($0.4)	($3.6)	$36.5	2%
12	East	Interface	500	$16.9	($13.2)	$0.8	$30.9	($0.1)	($0.0)	$0.0	($0.0)	$30.8	2%
13	Branchburg - Readington	Line	PSEG	$30.4	($11.9)	$4.7	$47.0	($6.4)	$8.8	($2.0)	($17.2)	$29.8	2%
14	Aqueduct - Doubs	Line	AP	$23.1	($3.7)	$0.4	$27.3	$0.0	($0.1)	($0.0)	$0.1	$27.4	2%
15	Central	Interface	500	$13.8	($11.0)	$1.6	$26.4	($0.0)	$0.0	$0.1	($0.0)	$26.4	1%
16	5004/5005 Interface	Interface	500	$12.9	($22.0)	$2.3	$37.3	($3.1)	$6.8	($1.8)	($11.7)	$25.6	1%
17	Axton	Transformer	AEP	$8.8	($14.6)	$1.5	$25.0	$0.0	$0.0	$0.0	$0.0	$25.0	1%
18	Harwood - Susquehanna	Line	PPL	$8.9	($19.6)	$0.4	$28.9	($2.6)	$3.0	($0.7)	($6.3)	$22.7	1%
19	Krendale - Seneca	Line	AP	$13.6	$2.7	$5.7	$16.6	($0.1)	$0.1	($0.0)	($0.2)	$16.4	1%
20	Bristers - Ox	Line	Dominion	$8.7	($7.4)	($0.9)	$15.3	$0.5	$0.4	$0.4	$0.5	$15.8	1%
21	North Seaford - Pine Street	Line	DPL	$21.2	$5.4	$0.1	$16.0	($1.0)	($0.6)	($0.1)	($0.6)	$15.4	1%
22	East Frankfort - Crete	Line	ComEd	$5.1	($6.3)	$2.6	$14.0	$0.0	$0.0	$0.0	$0.0	$14.0	1%
23	Branchburg - Flagtown	Line	PSEG	$11.8	($4.1)	$0.1	$16.0	$0.3	$1.0	($1.4)	($2.1)	$13.9	1%
24	Buckingham - Pleasant Valley	Line	PECO	$13.0	$1.0	$1.1	$13.1	($0.7)	$1.0	$0.2	($1.5)	$11.6	1%
25	Black Oak	Transformer	AP	$6.4	($4.8)	$0.4	$11.5	($0.2)	($0.3)	($0.1)	($0.0)	$11.5	1%

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Congestion-Event Summary for Midwest ISO Flowgates

Table 7-12 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through September 2009 (See 2008 SOM Table 7-11)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
Pana North	$0.1	($2.1)	$1.7	$3.9	($0.5)	$1.1	($11.5)	($13.0)	($9.1)	879	318
Crete - St Johns Tap	$2.7	($9.2)	$2.9	$14.7	($0.9)	$0.2	($5.1)	($6.2)	$8.5	732	190
Schahfer - Burr Oak	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	62	81
Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.7	($3.2)	($3.8)	($3.8)	0	161
Pleasant Prairie - Zion	($0.0)	($0.1)	$0.1	$0.2	$0.3	$0.5	($1.9)	($2.2)	($2.0)	51	45
Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($1.1)	($1.3)	($1.3)	0	44
Oak Grove - Galesburg	($0.5)	($3.8)	$0.1	$3.4	$0.7	$1.1	($4.0)	($4.5)	($1.1)	645	531
State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	($0.4)	($0.6)	($0.6)	0	30
Rising	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.5)	($0.5)	($0.5)	0	55
State Line - Wolf Lake	$0.3	($1.0)	$0.6	$1.9	($0.4)	$0.5	($1.5)	($2.4)	($0.5)	415	152
Pawnee	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.4)	($0.4)	($0.4)	0	35
Lanesville	$0.3	($0.1)	$0.1	$0.5	$0.0	$0.1	($0.8)	($0.9)	($0.4)	104	32
Pierce - Foster	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.3	($0.0)	($0.4)	($0.4)	0	5
Palisades - Argenta	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.2	($0.0)	($0.2)	($0.2)	0	8

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Table 7-13 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through September 2008 (See 2008 SOM Table 7-12)

	Congestion Costs (Millions)									Event Hours	
	Day Ahead				Balancing						
Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Pleasant Prairie - Zion	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.2	($5.3)	($6.2)	($6.2)	0	71
Pana North	$0.7	($1.8)	$0.6	$3.1	($0.4)	$1.2	($6.8)	($8.3)	($5.3)	190	299
Lanesville	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.5	($3.8)	($4.4)	($4.4)	0	87
State Line - Wolf Lake	$2.0	($3.6)	$4.2	$9.8	($1.0)	$1.2	($4.0)	($6.3)	$3.6	1,129	366
Dunes Acres - Michigan City	$3.2	($2.8)	$2.2	$8.1	($1.4)	$1.0	($8.7)	($11.1)	($3.0)	310	263
Crete - St Johns Tap	$0.9	($1.3)	$0.3	$2.5	($0.2)	$0.1	($0.4)	($0.7)	$1.8	80	14
Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	($0.3)	($0.4)	($0.4)	0	9
State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.3)	($0.4)	($0.4)	0	37
Ontario Hydro - NYISO	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.1)	($0.0)	($0.2)	($0.2)	0	15
Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.0)	($0.2)	($0.2)	0	23
Salem	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	0	1
DC Cook - Palisades	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	0	3
Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	2
State Line	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Eau Claire - Arpin	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	8

Congestion-Event Summary for the 500 kV System

Table 7-14 Regional constraints summary (By facility): January through September 2009 (See 2008 SOM Table 7-13)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
West	Interface	500	$17.8	($21.4)	$0.6	$39.7	$0.3	($0.2)	$0.1	$0.7	$40.4	391	85
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
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
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
AEP-DOM	Interface	500	$0.5	($3.1)	$0.3	$3.9	($0.5)	($0.0)	($0.3)	($0.8)	$3.1	126	64
East	Interface	500	$0.2	($0.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	21	0
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
Central	Interface	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	$0.1	19	8
Harrison - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	4

Table 7-15 Regional constraints summary (By facility): January through September 2008 (See 2008 SOM Table 7-14)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$175.2	($283.1)	$17.5	$475.8	($12.1)	$7.1	($8.5)	($27.7)	$448.1	2,182	788
Bedington - Black Oak	Interface	500	$49.5	($99.9)	$6.5	$155.9	($1.0)	($0.3)	$0.7	($0.1)	$155.9	1,361	209
West	Interface	500	$56.2	($33.8)	$6.0	$96.0	($1.9)	$8.3	($2.1)	($12.3)	$83.7	1,197	372
Kammer	Transformer	500	$90.0	$20.4	$8.3	$77.8	($15.7)	($2.0)	$2.8	($10.9)	$67.0	2,251	1,261
East	Interface	500	$16.9	($13.2)	$0.8	$30.9	($0.1)	($0.0)	$0.0	($0.0)	$30.8	510	9
Central	Interface	500	$13.8	($11.0)	$1.6	$26.4	($0.0)	$0.0	$0.1	($0.0)	$26.4	701	22
5004/5005 Interface	Interface	500	$12.9	($22.0)	$2.3	$37.3	($3.1)	$6.8	($1.8)	($11.7)	$25.6	427	365
Fort Martin - Harrison	Line	500	$2.0	($0.3)	$0.4	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	45	0
Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.4	$0.2	($1.0)	($1.0)	0	21
Conemaugh - Keystone	Line	500	$0.4	($0.2)	$0.2	$0.8	$0.9	$0.8	($0.1)	$0.1	$0.9	16	36
Cabot - Wylie Ridge	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7	($0.1)	($0.8)	($0.8)	0	6
AEP-DOM	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.1)	($0.2)	($0.2)	0	5
Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.1	$0.1	$0.1	0	6

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Zonal Congestion

Summary

Table 7-16 Congestion cost summary (By control zone): January through September 2009 (See 2008 SOM Table 7-16)

	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
DPL	$43.7	$13.0	$0.4	$31.1	($2.0)	$1.5	($0.4)	($4.0)	$27.1
Dominion	$73.8	($0.8)	$6.3	$80.8	$0.2	($3.9)	($7.6)	($3.4)	$77.4
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
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
Pepco	$158.9	$106.0	$2.3	$55.3	($18.8)	($8.6)	($2.5)	($12.7)	$42.6
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

Table 7-17 Congestion cost summary (By control zone): January through September 2008 (See 2008 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	$96.7	$25.8	$1.0	$71.9	($13.1)	$7.6	($1.7)	($22.5)	$49.4
AEP	($319.6)	($593.6)	$9.4	$283.4	($78.3)	$1.5	($3.9)	($83.8)	$199.7
AP	$125.5	($320.3)	$35.1	$480.9	($13.6)	$20.7	($23.9)	($58.2)	$422.7
BGE	$264.6	$205.8	$2.6	$61.4	$8.0	($12.6)	($3.5)	$17.1	$78.5
ComEd	($382.9)	($645.9)	($0.5)	$262.5	($39.4)	$9.8	($4.0)	($53.1)	$209.4
DAY	($39.8)	($48.9)	$0.3	$9.4	$3.4	$1.9	($0.2)	$1.2	$10.6
DLCO	($129.9)	($198.2)	($0.0)	$68.2	($44.8)	$18.8	$0.1	($63.5)	$4.7
DPL	$125.8	$44.5	$0.8	$82.1	$6.9	$5.8	($1.4)	($0.3)	$81.7
Dominion	$291.2	$7.6	$32.2	$315.8	($9.5)	$3.6	($30.1)	($43.2)	$272.6
External	($54.8)	($38.7)	$11.5	($4.6)	($33.2)	($28.6)	($71.9)	($76.4)	($81.0)
JCPL	$231.9	$61.2	$9.0	$179.7	($0.4)	$0.8	($8.8)	($10.0)	$169.7
Met-Ed	$86.2	$82.2	$2.7	$6.7	$2.5	$1.5	$11.2	$12.2	$18.9
PECO	$59.0	$95.1	$0.5	($35.7)	$0.0	$14.3	($0.7)	($15.0)	($50.6)
PENELEC	($41.7)	($198.9)	$4.4	$161.6	($6.0)	$10.4	($1.2)	($17.6)	$144.0
PPL	$25.5	$29.1	$10.5	$6.9	$0.2	$6.5	($4.4)	($10.7)	($3.9)
PSEG	$242.5	$157.1	$25.8	$111.2	$4.9	$32.2	($23.9)	($51.2)	$60.0
Pepco	$538.2	$364.7	$6.2	$179.8	$6.7	($3.6)	($6.9)	$3.5	$183.3
RECO	$8.4	$0.1	$1.4	$9.7	$0.6	($0.1)	($2.0)	($1.2)	$8.5
Total	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$1,778.2

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Details of Regional and Zonal Congestion

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-18 AECO Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-18)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
West	Interface	500	$4.6	$2.2	$0.0	$2.4	$0.0	($0.0)	($0.0)	$0.0	$2.4	391	85
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
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
Wylie Ridge	Transformer	AP	$1.8	$0.9	$0.0	$0.9	($0.0)	$0.1	$0.1	($0.0)	$0.9	354	335
Absecon - Lewis	Line	AECO	$1.0	$0.1	$0.0	$1.0	($1.2)	$0.5	($0.0)	($1.7)	($0.8)	22	149
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
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
Monroe	Transformer	AECO	$0.5	$0.0	$0.0	$0.4	$0.1	($0.0)	$0.0	$0.1	$0.5	252	13
Shieldalloy - Vineland	Line	AECO	$1.1	$0.3	$0.0	$0.9	($0.3)	$0.1	($0.0)	($0.4)	$0.5	148	61
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
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
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
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	0
Cloverdale - Lexington	Line	AEP	$0.4	$0.2	$0.0	$0.2	$0.1	($0.0)	$0.0	$0.1	$0.3	752	335

Table 7-19 AECO Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-19)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Monroe	Transformer	AECO	$33.9	$3.6	$0.2	$30.5	($14.5)	$4.3	($0.7)	($19.5)	$11.0	810	254
AP South	Interface	500	$11.6	$5.0	$0.2	$6.8	$0.1	$0.1	($0.1)	($0.1)	$6.7	2,182	788
West	Interface	500	$10.2	$4.6	$0.1	$5.6	$0.4	($0.0)	($0.1)	$0.4	$6.1	1,197	372
Atlantic - Larrabee	Line	JCPL	($6.4)	($2.8)	($0.0)	($3.6)	($0.4)	$0.4	$0.0	($0.7)	($4.4)	1,501	368
Cloverdale - Lexington	Line	AEP	$7.4	$3.9	$0.0	$3.5	$0.6	($0.1)	($0.1)	$0.7	$4.2	2,941	1,506
Kammer	Transformer	500	$6.4	$3.1	$0.1	$3.4	$0.4	$0.1	($0.1)	$0.2	$3.6	2,251	1,261
Churchtown	Transformer	AECO	($0.3)	($3.0)	$0.0	$2.7	$0.4	$0.3	$0.0	$0.1	$2.8	179	92
Quinton - Roadstown	Line	AECO	$6.3	$1.0	$0.0	$5.3	($1.3)	$1.4	($0.1)	($2.8)	$2.5	288	124
Central	Interface	500	$4.5	$2.4	$0.0	$2.1	$0.0	$0.0	($0.0)	($0.0)	$2.1	701	22
East	Interface	500	$4.0	$2.2	$0.0	$1.9	($0.0)	$0.0	$0.0	($0.0)	$1.9	510	9
5004/5005 Interface	Interface	500	$2.9	$1.2	$0.0	$1.7	$0.0	$0.0	($0.0)	($0.0)	$1.6	427	365
Bedington - Black Oak	Interface	500	$2.3	$1.2	$0.0	$1.2	$0.0	$0.0	($0.0)	$0.0	$1.2	1,361	209
Mount Storm - Pruntytown	Line	AP	$2.1	$0.9	$0.1	$1.3	($0.1)	$0.0	($0.2)	($0.3)	$1.0	1,546	771
Sammis - Wylie Ridge	Line	AP	$1.1	$0.7	$0.0	$0.4	$0.5	$0.1	($0.1)	$0.3	$0.7	708	789
Dickerson - Pleasant View	Line	Pepco	$1.4	$0.7	$0.0	$0.7	$0.0	($0.0)	($0.0)	$0.1	$0.7	468	124

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BGE Control Zone

Table 7-20 BGE Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-20)

			Congestion Costs (Millions)											
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
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
West	Interface	500	$8.1	$6.8	$0.2	$1.4	$0.1	($0.2)	($0.0)	$0.2	$1.6	391	85
Wylie Ridge	Transformer	AP	$3.6	$3.4	$0.1	$0.3	$0.6	($0.7)	($0.2)	$1.2	$1.5	354	335
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
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
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
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
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
Cloverdale - Lexington	Line	AEP	$2.3	$2.2	$0.0	$0.2	$0.3	($0.1)	($0.0)	$0.4	$0.5	752	335
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
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
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
Elrama - Mitchell	Line	AP	$0.7	$0.4	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.4	225	184

Table 7-21 BGE Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-21)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$73.3	$57.1	$0.5	$16.7	$4.1	($3.6)	($0.8)	$6.9	$23.6	2,182	788
Mount Storm - Pruntytown	Line	AP	$31.2	$25.6	$0.2	$5.8	$0.1	($2.3)	($0.1)	$2.3	$8.0	1,546	771
West	Interface	500	$17.0	$12.7	$0.3	$4.6	$1.1	($0.7)	($0.6)	$1.3	$5.9	1,197	372
Kammer	Transformer	500	$16.7	$13.6	$0.4	$3.5	$1.1	($1.3)	($0.4)	$2.0	$5.5	2,251	1,261
Aqueduct - Doubs	Line	AP	$11.9	$6.8	$0.0	$5.1	($0.0)	($0.0)	($0.0)	$0.0	$5.1	293	7
Pumphrey - Westport	Line	Pepco	$4.0	($0.3)	$0.0	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	1,039	0
Bedington - Black Oak	Interface	500	$23.1	$21.3	$0.3	$2.1	$0.8	($0.6)	($0.1)	$1.3	$3.4	1,361	209
Conastone	Transformer	BGE	$4.4	$1.4	($0.0)	$3.1	$0.1	($0.0)	$0.0	$0.1	$3.2	95	14
Dickerson - Pleasant View	Line	Pepco	$6.1	$3.8	$0.3	$2.5	$0.3	($0.1)	($0.1)	$0.3	$2.8	468	124
Mount Storm	Transformer	AP	$12.5	$10.8	$0.1	$1.8	($0.3)	($1.0)	($0.1)	$0.7	$2.5	908	460
Green Street - Westport	Line	BGE	$2.3	($0.0)	$0.0	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	308	0
Cloverdale - Lexington	Line	AEP	$37.2	$38.3	$0.4	($0.7)	$2.0	($1.0)	($0.3)	$2.7	$1.9	2,941	1,506
Sammis - Wylie Ridge	Line	AP	$2.5	$2.3	$0.0	$0.2	$0.9	($0.7)	($0.4)	$1.2	$1.5	708	789
5004/5005 Interface	Interface	500	$2.4	$1.4	$0.1	$1.1	$0.1	($0.2)	($0.1)	$0.2	$1.3	427	365
Brandon Shores - Riverside	Line	BGE	$1.3	($0.7)	$0.0	$2.0	($0.6)	$0.2	($0.0)	($0.9)	$1.2	124	58

DPL Control Zone

Table 7-22 DPL Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-22)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
West	Interface	500	$8.6	$3.6	$0.0	$5.1	($0.0)	$0.1	($0.0)	($0.1)	$4.9	391	85
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
Short - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.2	($0.1)	($2.4)	($2.4)	0	27
Wylie Ridge	Transformer	AP	$3.4	$1.3	$0.0	$2.1	$0.2	$0.2	($0.0)	($0.0)	$2.1	354	335
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
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
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
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
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
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
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	0
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
Cloverdale - Lexington	Line	AEP	$0.9	$0.2	$0.0	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.7	752	335
Easton - Trappe	Line	DPL	$0.7	$0.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	146	0

Table 7-23 DPL Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-23)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
North Seaford - Pine Street	Line	DPL	$21.2	$5.4	$0.1	$16.0	($1.0)	($0.6)	($0.1)	($0.6)	$15.4	689	147
AP South	Interface	500	$20.2	$9.7	$0.1	$10.7	$1.5	$1.2	($0.1)	$0.2	$10.9	2,182	788
West	Interface	500	$16.0	$5.9	$0.1	$10.3	$1.0	$1.0	($0.0)	$0.0	$10.3	1,197	372
Cloverdale - Lexington	Line	AEP	$13.3	$4.3	$0.1	$9.1	$0.9	($0.0)	($0.1)	$0.9	$10.0	2,941	1,506
Kammer	Transformer	500	$10.7	$3.9	$0.1	$6.8	$1.0	$0.7	($0.1)	$0.2	$7.1	2,251	1,261
East	Interface	500	$6.8	$2.3	$0.0	$4.6	$0.0	($0.0)	$0.0	$0.0	$4.6	510	9
Central	Interface	500	$7.5	$3.3	$0.0	$4.2	$0.0	($0.0)	$0.0	$0.1	$4.2	701	22
Bedington - Black Oak	Interface	500	$4.8	$1.8	$0.0	$2.9	$0.2	$0.0	($0.0)	$0.1	$3.1	1,361	209
Atlantic - Larrabee	Line	JCPL	($4.4)	($1.9)	($0.0)	($2.5)	($0.5)	($0.0)	$0.0	($0.4)	($2.9)	1,501	368
5004/5005 Interface	Interface	500	$4.5	$1.7	$0.0	$2.8	$0.5	$0.4	($0.1)	$0.1	$2.9	427	365
Mount Storm - Pruntytown	Line	AP	$4.3	$1.7	$0.1	$2.6	$0.3	$0.2	($0.1)	$0.0	$2.6	1,546	771
Red Lion At5n	Transformer	DPL	$3.8	$1.4	$0.1	$2.5	$0.0	($0.1)	$0.0	$0.1	$2.5	53	3
Branchburg - Readington	Line	PSEG	($3.3)	($1.4)	($0.1)	($1.9)	($0.2)	$0.3	$0.1	($0.4)	($2.3)	1,117	271
Dickerson - Pleasant View	Line	Pepco	$2.4	$1.0	$0.0	$1.4	$0.1	($0.1)	($0.0)	$0.2	$1.6	468	124
Sammis - Wylie Ridge	Line	AP	$2.0	$0.5	$0.0	$1.5	$0.8	$0.7	($0.1)	$0.1	$1.6	708	789

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JCPL Control Zone

Table 7-24 JCPL Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-24)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	$9.7	$3.9	$0.0	$5.7	$0.1	($0.2)	($0.0)	$0.2	$6.0	391	85
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
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
Wylie Ridge	Transformer	AP	$3.9	$1.4	$0.0	$2.5	$0.1	($0.6)	($0.0)	$0.7	$3.2	354	335
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
Atlantic - Larrabee	Line	JCPL	$1.8	$0.4	$0.0	$1.5	($0.6)	($0.5)	($0.0)	($0.1)	$1.3	188	45
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
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
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
East Frankfort - Crete	Line	ComEd	$1.3	$0.5	($0.0)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,490	0
Cloverdale - Lexington	Line	AEP	$0.9	$0.3	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	752	335
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
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
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
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

Table 7-25 JCPL Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-25)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Atlantic - Larrabee	Line	JCPL	$47.2	$2.1	$2.2	$47.2	($3.0)	$2.7	($2.4)	($8.1)	$39.1	1,501	368
Branchburg - Readington	Line	PSEG	$27.7	$4.5	$2.2	$25.4	($2.2)	($0.8)	($1.8)	($3.3)	$22.1	1,117	271
West	Interface	500	$24.3	$9.5	$0.3	$15.1	$0.1	($0.2)	($0.6)	($0.4)	$14.7	1,197	372
Cloverdale - Lexington	Line	AEP	$17.5	$4.8	$0.7	$13.4	$0.6	($0.2)	($0.5)	$0.2	$13.6	2,941	1,506
AP South	Interface	500	$20.7	$8.4	$0.8	$13.0	$0.2	($0.4)	($1.0)	($0.5)	$12.6	2,182	788
Kammer	Transformer	500	$16.2	$5.7	$0.4	$11.0	$0.5	$0.1	($0.4)	$0.1	$11.1	2,251	1,261
Central	Interface	500	$12.1	$3.5	$0.5	$9.0	$0.0	($0.0)	($0.0)	($0.0)	$9.0	701	22
Branchburg - Flagtown	Line	PSEG	$10.9	$2.8	$0.1	$8.2	$1.4	$0.6	($0.1)	$0.7	$8.8	260	61
Cedar Grove - Roseland	Line	PSEG	($8.5)	($1.6)	($0.1)	($7.1)	($0.4)	($0.4)	$0.1	$0.1	($7.0)	627	178
Buckingham - Pleasant Valley	Line	PECO	$9.9	$3.5	$0.2	$6.7	($0.1)	($0.1)	($0.1)	($0.1)	$6.5	557	60
East	Interface	500	$8.8	$2.6	$0.0	$6.2	($0.0)	($0.0)	($0.0)	($0.0)	$6.2	510	9
5004/5005 Interface	Interface	500	$8.2	$2.9	$0.3	$5.6	$0.3	$0.1	($0.2)	$0.0	$5.6	427	365
Redoak - Sayreville	Line	JCPL	$0.1	($2.2)	$0.0	$2.3	$0.2	($0.5)	$0.4	$1.1	$3.4	237	30
Harwood - Susquehanna	Line	PPL	$4.5	$1.3	$0.0	$3.2	$0.0	($0.0)	($0.0)	$0.1	$3.2	110	99
Cedar Grove - Clifton	Line	PSEG	($3.7)	($0.6)	($0.0)	($3.1)	($0.3)	($0.3)	$0.2	$0.2	($2.9)	494	403

Met-Ed Control Zone

Table 7-26 Met-Ed Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-26)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
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
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
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
Hunterstown	Transformer	Met-Ed	$0.3	($0.1)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	($0.0)	$0.4	53	1
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
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
Wylie Ridge	Transformer	AP	$3.1	$2.8	$0.0	$0.3	($0.1)	($0.2)	($0.0)	$0.0	$0.3	354	335
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	0
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
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
West	Interface	500	$6.9	$6.8	$0.0	$0.1	($0.0)	($0.1)	($0.0)	$0.1	$0.2	391	85
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
Cloverdale - Lexington	Line	AEP	$0.7	$0.9	$0.0	($0.2)	($0.0)	($0.0)	($0.0)	($0.0)	($0.2)	752	335

Table 7-27 Met-Ed Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-27)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$15.7	$17.0	$0.7	($0.7)	$0.5	($0.2)	$3.4	$4.1	$3.4	2,182	788
Cloverdale - Lexington	Line	AEP	$11.4	$10.6	$0.7	$1.5	$0.2	$0.4	$0.5	$0.4	$1.9	2,941	1,506
Kammer	Transformer	500	$9.1	$9.6	$0.5	($0.0)	$0.2	($0.1)	$1.4	$1.6	$1.6	2,251	1,261
Bedington - Black Oak	Interface	500	$4.1	$3.2	$0.1	$0.9	$0.0	$0.0	$0.6	$0.7	$1.6	1,361	209
Bedington	Transformer	AP	$1.7	$0.3	$0.0	$1.4	$0.0	$0.0	$0.2	$0.2	$1.6	999	234
Brunner Island - Yorkana	Line	Met-Ed	$0.5	($0.9)	$0.0	$1.4	$0.1	$0.1	($0.0)	($0.0)	$1.4	57	25
Middletown Jct	Transformer	Met-Ed	$1.0	($0.1)	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	59	1
Collins - Middletown Jct	Line	Met-Ed	$1.0	($0.0)	$0.0	$1.0	($0.0)	$0.2	$0.1	($0.1)	$0.9	265	31
Conastone	Transformer	BGE	$0.4	($0.3)	($0.1)	$0.7	$0.0	$0.1	$0.1	$0.0	$0.7	95	14
Sammis - Wylie Ridge	Line	AP	$1.8	$1.9	$0.1	$0.0	$0.4	$0.0	$0.3	$0.6	$0.6	708	789
East Towanda	Transformer	PENELEC	$0.3	$0.4	$0.0	$0.0	$0.1	($0.1)	$0.4	$0.6	$0.6	803	306
Harwood - Susquehanna	Line	PPL	$1.2	$0.4	$0.0	$0.8	$0.0	$0.3	($0.0)	($0.2)	$0.6	110	99
Aqueduct - Doubs	Line	AP	($0.8)	($0.2)	$0.0	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	293	7
Mount Storm - Pruntytown	Line	AP	$3.4	$3.1	$0.1	$0.4	($0.0)	$0.0	$0.2	$0.2	$0.6	1,546	771
Altoona - Raystown	Line	PENELEC	$0.4	$0.4	$0.0	$0.0	$0.0	($0.1)	$0.4	$0.5	$0.5	161	48

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PECO Control Zone

Table 7-28 PECO Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-28)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
West	Interface	500	$3.0	$6.2	$0.0	($3.1)	($0.0)	($0.1)	($0.0)	$0.0	($3.1)	391	85
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
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
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
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
Wylie Ridge	Transformer	AP	$1.3	$2.3	$0.0	($0.9)	($0.1)	$0.0	($0.1)	($0.1)	($1.1)	354	335
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
East Frankfort - Crete	Line	ComEd	$0.4	$1.3	($0.0)	($0.8)	$0.0	$0.0	$0.0	$0.0	($0.8)	1,490	0
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
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
Cloverdale - Lexington	Line	AEP	$0.4	$1.1	$0.0	($0.7)	($0.0)	($0.0)	($0.0)	$0.0	($0.7)	752	335
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
Holmesburg - Richmond	Line	PECO	($0.2)	($0.5)	($0.0)	$0.3	($0.0)	($0.1)	$0.0	$0.1	$0.5	311	10
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

Table 7-29 PECO Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-29)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$7.4	$24.3	$0.0	($16.9)	$0.1	$1.2	$0.0	($1.1)	($18.0)	2,182	788
West	Interface	500	$7.6	$18.2	$0.1	($10.5)	$0.2	$1.7	$0.0	($1.5)	($12.0)	1,197	372
East	Interface	500	$7.8	$0.1	($0.0)	$7.7	($0.0)	($0.1)	$0.0	$0.1	$7.8	510	9
Kammer	Transformer	500	$6.1	$12.3	$0.0	($6.2)	$0.5	$1.0	$0.0	($0.5)	($6.7)	2,251	1,261
Cloverdale - Lexington	Line	AEP	$7.9	$13.3	$0.1	($5.3)	$0.1	$1.4	($0.0)	($1.3)	($6.7)	2,941	1,506
Bedington - Black Oak	Interface	500	$1.5	$5.9	$0.0	($4.3)	$0.0	$0.2	$0.0	($0.1)	($4.4)	1,361	209
Mount Storm - Pruntytown	Line	AP	$1.1	$5.1	$0.0	($3.9)	($0.1)	$0.2	($0.0)	($0.3)	($4.2)	1,546	771
5004/5005 Interface	Interface	500	$2.4	$4.9	$0.0	($2.5)	$0.2	$0.7	($0.0)	($0.6)	($3.1)	427	365
Branchburg - Readington	Line	PSEG	($1.9)	($4.5)	($0.0)	$2.6	($0.0)	$0.2	($0.0)	($0.3)	$2.3	1,117	271
Conastone	Transformer	BGE	($0.2)	($2.4)	($0.0)	$2.2	$0.0	($0.0)	($0.0)	$0.0	$2.3	95	14
Dickerson - Pleasant View	Line	Pepco	$1.4	$3.5	$0.0	($2.2)	($0.0)	($0.0)	$0.0	$0.0	($2.2)	468	124
Bradford - Planebrook	Line	PECO	$0.7	($1.1)	($0.0)	$1.8	$0.0	$0.1	$0.0	($0.1)	$1.7	124	23
Whitpain	Transformer	PECO	$3.8	($1.4)	$0.1	$5.2	($0.4)	$2.8	($0.3)	($3.5)	$1.7	89	68
Sammis - Wylie Ridge	Line	AP	$1.6	$1.8	$0.0	($0.2)	$0.0	$1.6	$0.0	($1.5)	($1.7)	708	789
Unclassified	Unclassified	Unclassified	$2.2	$0.6	($0.0)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	NA	NA

PENELEC Control Zone

Table 7-30 PENELEC Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-30)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
West	Interface	500	($2.2)	($15.2)	($0.0)	$13.0	$0.0	$0.1	$0.0	($0.0)	$13.0	391	85
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
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
Wylie Ridge	Transformer	AP	$1.5	$10.3	$0.1	($8.8)	($0.6)	($0.7)	($0.0)	$0.1	($8.7)	354	335
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
Seward	Transformer	PENELEC	$6.5	$3.7	($0.0)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	218	0
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
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
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
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
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	0
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
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
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

Table 7-31 PENELEC Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-31)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	($6.7)	($39.1)	($0.3)	$32.1	$0.1	$1.5	$0.3	($1.1)	$31.0	1,197	372
AP South	Interface	500	($27.6)	($54.1)	$0.3	$26.9	$3.1	$0.8	$0.6	$3.0	$29.9	2,182	788
Mount Storm - Pruntytown	Line	AP	($22.0)	($45.3)	$0.0	$23.3	$0.8	($0.3)	$0.0	$1.1	$24.4	1,546	771
Bedington - Black Oak	Interface	500	($15.7)	($35.4)	$0.1	$19.8	$0.7	$0.4	$0.1	$0.4	$20.2	1,361	209
Kammer	Transformer	500	$9.0	$29.5	$0.7	($19.8)	($0.8)	($1.2)	$0.2	$0.6	($19.2)	2,251	1,261
5004/5005 Interface	Interface	500	($2.6)	($15.5)	($0.0)	$12.9	($0.7)	$0.9	$0.1	($1.5)	$11.4	427	365
Seward	Transformer	PENELEC	$24.5	$14.4	$0.0	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	225	0
Mount Storm	Transformer	AP	($8.1)	($17.6)	$0.1	$9.5	($0.8)	$0.0	($0.0)	($0.8)	$8.7	908	460
Central	Interface	500	($0.5)	($8.5)	($0.0)	$7.9	$0.0	$0.0	$0.0	$0.0	$8.0	701	22
Sammis - Wylie Ridge	Line	AP	$2.0	$8.2	$0.4	($5.8)	($0.6)	($0.3)	($1.0)	($1.3)	($7.1)	708	789
Krendale - Seneca	Line	AP	$3.1	$10.0	$0.3	($6.7)	$0.0	($0.0)	($0.0)	$0.0	($6.6)	960	16
East Towanda	Transformer	PENELEC	$14.1	($8.8)	$1.0	$23.8	($9.2)	$8.4	($0.5)	($18.1)	$5.7	803	306
East	Interface	500	($0.9)	($4.8)	($0.1)	$3.8	($0.0)	$0.0	$0.0	($0.0)	$3.8	510	9
Bedington	Transformer	AP	($0.5)	($4.1)	$0.0	$3.6	$0.1	($0.0)	$0.0	$0.2	$3.8	999	234
Altoona - Bear Rock	Line	PENELEC	($4.0)	($7.2)	($0.0)	$3.1	$0.2	$0.0	($0.0)	$0.2	$3.3	173	16

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Pepco Control Zone

Table 7-32 Pepco Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-32)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
Buzzard - Ritchie	Line	Pepco	$25.3	$3.2	$0.2	$22.3	($13.9)	$1.9	($0.6)	($16.4)	$5.9	409	149
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
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
West	Interface	500	$8.1	$6.0	$0.0	$2.1	($0.1)	($0.1)	($0.0)	$0.0	$2.2	391	85
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
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
Wylie Ridge	Transformer	AP	$6.2	$4.9	$0.0	$1.3	($0.3)	($0.7)	($0.0)	$0.3	$1.7	354	335
Cloverdale - Lexington	Line	AEP	$5.3	$3.9	$0.1	$1.5	($0.2)	($0.4)	($0.1)	$0.1	$1.6	752	335
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
East Frankfort - Crete	Line	ComEd	$2.4	$1.6	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,490	0
Mount Storm	Transformer	AP	$1.7	$1.3	$0.0	$0.5	$0.0	($0.3)	($0.1)	$0.2	$0.7	123	70
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
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

Table 7-33 Pepco Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-33)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$155.6	$107.7	$1.4	$49.3	($2.6)	($0.7)	($1.6)	($3.6)	$45.8	2,182	788
Cloverdale - Lexington	Line	AEP	$83.9	$59.7	$1.7	$25.9	$5.6	($1.3)	($1.6)	$5.3	$31.2	2,941	1,506
Mount Storm - Pruntytown	Line	AP	$68.5	$48.9	$0.3	$20.0	$0.8	($1.5)	($0.3)	$2.1	$22.1	1,546	771
Bedington - Black Oak	Interface	500	$55.5	$37.6	$0.5	$18.4	($0.4)	($0.4)	($0.2)	($0.2)	$18.3	1,361	209
Aqueduct - Doubs	Line	AP	$37.6	$22.9	$0.1	$14.8	$0.1	($0.0)	($0.0)	$0.1	$14.9	293	7
Kammer	Transformer	0	$32.7	$21.6	$0.7	$11.7	($0.4)	($0.7)	($0.6)	($0.2)	$11.5	2,251	1,261
Mount Storm	Transformer	AP	$25.3	$18.7	$0.1	$6.8	$2.1	($0.6)	($0.1)	$2.5	$9.3	908	460
West	Interface	500	$19.4	$12.0	$0.5	$7.8	($0.3)	($0.5)	($0.6)	($0.4)	$7.4	1,197	372
Dickerson - Pleasant View	Line	Pepco	$18.2	$12.3	$0.6	$6.5	($0.2)	($0.3)	($0.6)	($0.4)	$6.1	468	124
Dickerson - Quince Orchard	Line	Pepco	$3.4	$1.1	$0.0	$2.4	($0.0)	($0.0)	$0.0	($0.0)	$2.4	46	2
Central	Interface	500	($8.0)	($6.0)	($0.1)	($2.1)	$0.0	$0.0	($0.0)	$0.0	($2.1)	701	22
Black Oak	Transformer	AP	$6.2	$4.2	$0.0	$2.0	($0.0)	($0.1)	($0.0)	$0.1	$2.1	384	29
Brighton	Transformer	Pepco	$6.1	$3.9	$0.0	$2.3	($0.2)	$0.1	($0.1)	($0.4)	$1.9	37	32
Branchburg - Readington	Line	PSEG	($5.3)	($3.5)	($0.2)	($2.0)	$0.3	$0.2	$0.2	$0.2	($1.8)	1,117	271
Bristers - Ox	Line	Dominion	$5.9	$3.9	$0.0	$2.0	($0.0)	$0.1	($0.1)	($0.2)	$1.7	77	38

PPL Control Zone

Table 7-34 PPL Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-34)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
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
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
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
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
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
West	Interface	500	$2.8	$4.1	$0.5	($0.8)	($0.0)	($0.2)	($0.0)	$0.1	($0.6)	391	85
Harwood - Susquehanna	Line	PPL	$0.1	($0.4)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	13	0
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
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	0
Wylie Ridge	Transformer	AP	$1.1	$1.8	$0.3	($0.4)	$0.2	$0.1	$0.0	$0.1	($0.3)	354	335
PL North	Interface	PPL	$0.0	$0.0	$0.0	$0.0	$0.4	$0.6	($0.0)	($0.3)	($0.3)	0	176
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
Atlantic - Larrabee	Line	JCPL	$0.0	$0.1	$0.0	($0.1)	($0.1)	$0.1	$0.0	($0.2)	($0.3)	188	45

Table 7-35 PPL Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-35)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Harwood - Susquehanna	Line	PPL	$2.6	($14.3)	($0.1)	$16.7	($1.2)	$2.0	$0.2	($3.0)	$13.7	110	99
West	Interface	500	$2.3	$10.5	$1.2	($7.1)	$0.2	$1.0	($0.1)	($1.0)	($8.0)	1,197	372
Cloverdale - Lexington	Line	AEP	$1.3	$8.2	$1.6	($5.2)	($0.2)	$0.1	($0.0)	($0.3)	($5.6)	2,941	1,506
East Towanda	Transformer	PENELEC	$0.4	$1.8	$0.0	($1.4)	$0.1	$1.1	($2.9)	($3.8)	($5.2)	803	306
Kammer	Transformer	500	$1.7	$6.5	$1.3	($3.5)	$0.2	$0.5	($0.2)	($0.6)	($4.1)	2,251	1,261
East	Interface	500	$0.1	($3.5)	($0.0)	$3.6	$0.0	($0.0)	$0.0	$0.0	$3.6	510	9
Central	Interface	500	$0.8	$4.9	$0.4	($3.6)	$0.0	($0.1)	($0.0)	$0.1	($3.5)	701	22
Mount Storm - Pruntytown	Line	AP	$1.3	($0.9)	$0.7	$2.9	$0.1	$0.2	($0.1)	($0.1)	$2.8	1,546	771
Sammis - Wylie Ridge	Line	AP	$0.1	$2.0	$0.3	($1.6)	$0.1	$0.4	($0.6)	($0.9)	($2.5)	708	789
5004/5005 Interface	Interface	500	$1.0	$3.6	$0.6	($2.0)	($0.1)	$0.1	($0.3)	($0.5)	($2.5)	427	365
Branchburg - Readington	Line	PSEG	$0.7	($0.7)	($0.1)	$1.4	$0.0	($0.1)	$0.1	$0.2	$1.6	1,117	271
Bedington - Black Oak	Interface	500	$1.5	$0.6	$0.5	$1.4	$0.1	$0.1	$0.1	$0.1	$1.5	1,361	209
Krendale - Seneca	Line	AP	$0.4	$1.9	$0.2	($1.3)	($0.0)	$0.0	($0.0)	($0.0)	($1.3)	960	16
Conastone	Transformer	BGE	$0.1	($1.2)	($0.0)	$1.2	$0.0	($0.0)	$0.0	$0.1	$1.3	95	14
Mount Storm	Transformer	AP	$0.4	($0.6)	$0.3	$1.2	$0.1	$0.0	($0.2)	($0.1)	$1.1	908	460

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PSEG Control Zone

Table 7-36 PSEG Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-36)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
Plainsboro - Trenton	Line	PSEG	$3.5	($0.1)	$0.1	$3.8	($0.3)	$0.4	($0.1)	($0.7)	$3.1	389	164
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
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
Fairlawn - Saddlebrook	Line	PSEG	$1.1	$0.2	$0.6	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	841	0
West	Interface	500	$10.9	$12.7	$0.8	($1.0)	($0.1)	$0.1	($0.2)	($0.3)	($1.3)	391	85
Wylie Ridge	Transformer	AP	$4.3	$5.4	$0.5	($0.6)	$0.0	$0.1	($0.6)	($0.7)	($1.3)	354	335
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
Hillsdale - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.3	($0.4)	($0.8)	($0.8)	0	47
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
Atlantic - Larrabee	Line	JCPL	$0.3	($0.5)	$0.0	$0.8	$0.0	$0.1	($0.1)	($0.2)	$0.6	188	45
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
Brunswick - Edison	Line	PSEG	$1.0	($0.0)	$0.0	$1.1	($0.1)	$0.2	($0.2)	($0.5)	$0.6	138	76
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

Table 7-37 PSEG Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-37)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Atlantic - Larrabee	Line	JCPL	$13.2	($5.9)	$0.3	$19.5	$0.5	$2.7	($0.8)	($3.0)	$16.5	1,501	368
Branchburg - Readington	Line	PSEG	$16.3	$0.8	$0.6	$16.1	$0.2	$2.9	($0.7)	($3.3)	$12.8	1,117	271
Buckingham - Pleasant Valley	Line	PECO	$10.3	$2.3	$0.5	$8.4	($0.1)	$0.4	($0.1)	($0.6)	$7.9	557	60
Branchburg - Flagtown	Line	PSEG	$6.7	$0.1	$0.2	$6.7	$0.4	($0.0)	($0.4)	($0.0)	$6.7	260	61
Cedar Grove - Roseland	Line	PSEG	$11.4	$1.8	$0.3	$9.9	($0.0)	$2.6	($0.9)	($3.5)	$6.4	627	178
Unclassified	Unclassified	Unclassified	$3.1	($2.8)	$0.1	$6.1	$0.0	$0.0	$0.0	$0.0	$6.1	NA	NA
AP South	Interface	500	$23.1	$28.0	$3.1	($1.8)	($0.1)	$1.0	($1.9)	($3.0)	($4.8)	2,182	788
Brunswick - Edison	Line	PSEG	$5.2	$0.3	$0.2	$5.1	($0.0)	$0.6	($0.3)	($0.9)	$4.2	NA	NA
Mount Storm - Pruntytown	Line	AP	$0.8	$4.8	$1.4	($2.6)	$0.1	($0.2)	($1.4)	($1.1)	($3.7)	1,546	771
Cloverdale - Lexington	Line	AEP	$20.4	$22.9	$2.4	($0.1)	$0.3	$1.8	($1.7)	($3.2)	($3.3)	2,941	1,506
Sammis - Wylie Ridge	Line	AP	$3.6	$4.1	$0.5	($0.1)	$0.7	$1.7	($2.0)	($3.0)	($3.1)	708	789
Trainer - Delco Tap	Line	PECO	($1.8)	($4.6)	($0.1)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1,658	0
Bedington - Black Oak	Interface	500	$3.6	$6.9	$1.0	($2.2)	$0.0	$0.0	($0.2)	($0.2)	($2.4)	1,361	209
Mount Storm	Transformer	AP	$0.0	$1.6	$0.7	($0.9)	$0.1	($0.1)	($1.0)	($0.8)	($1.7)	908	460
North Ave - Pvsc	Line	PSEG	$0.5	($1.0)	$0.0	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	453	0

RECO Control Zone

Table 7-38 RECO Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-38)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	391	85
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
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
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
Wylie Ridge	Transformer	AP	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	354	335
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
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
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
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	0
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
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
Fairlawn - Saddlebrook	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	841	0
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
Elrama - Mitchell	Line	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	225	184
Cloverdale - Lexington	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.0	752	335

Table 7-39 RECO Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-39)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Branchburg - Readington	Line	PSEG	$0.9	$0.0	$0.0	$1.0	$0.0	($0.0)	($0.0)	$0.0	$1.0	1,117	271
West	Interface	500	$1.1	$0.0	$0.2	$1.2	$0.1	($0.0)	($0.4)	($0.3)	$0.9	1,197	372
Cedar Grove - Roseland	Line	PSEG	$0.8	$0.0	$0.0	$0.7	$0.1	($0.0)	($0.0)	$0.1	$0.8	627	178
Kammer	Transformer	500	$0.7	$0.0	$0.1	$0.8	$0.0	($0.0)	($0.1)	($0.0)	$0.8	2,251	1,261
Cloverdale - Lexington	Line	AEP	$0.6	$0.0	$0.2	$0.8	$0.0	($0.0)	($0.1)	($0.1)	$0.7	2,941	1,506
AP South	Interface	500	$0.6	$0.0	$0.0	$0.7	$0.0	($0.0)	($0.1)	($0.1)	$0.6	2,182	788
Atlantic - Larrabee	Line	JCPL	$0.6	$0.0	$0.0	$0.6	$0.0	($0.0)	($0.1)	($0.0)	$0.5	1,501	368
Central	Interface	500	$0.5	$0.0	$0.0	$0.5	$0.0	($0.0)	$0.0	$0.0	$0.5	701	22
Buckingham - Pleasant Valley	Line	PECO	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	557	60
East	Interface	500	$0.4	$0.0	$0.0	$0.4	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	510	9
Cedar Grove - Clifton	Line	PSEG	$0.2	$0.0	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.3	494	403
Krendale - Seneca	Line	AP	$0.2	$0.0	$0.1	$0.2	($0.0)	($0.0)	$0.0	($0.0)	$0.2	960	16
Harwood - Susquehanna	Line	PPL	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	110	99
Dickerson - Pleasant View	Line	Pepco	$0.1	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	($0.0)	$0.2	468	124
5004/5005 Interface	Interface	500	$0.3	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.3)	($0.2)	$0.1	427	365

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Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-40 AEP Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-40)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
Ruth - Turner	Line	AEP	$4.9	($1.6)	$0.5	$7.0	($1.2)	($0.4)	($0.1)	($0.9)	$6.1	704	279
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
Kanawha - Kincaid	Line	AEP	$2.8	($2.1)	$0.2	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	291	0
Kammer - Ormet	Line	AEP	$7.8	$1.1	$0.3	$6.9	($1.6)	$0.5	($0.1)	($2.2)	$4.7	552	509
Kanawha River	Transformer	AEP	$3.2	($0.3)	$0.5	$4.0	$0.1	($0.3)	($0.1)	$0.4	$4.3	161	37
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
Breed - Wheatland	Line	AEP	$0.1	($3.7)	($0.4)	$3.4	$0.0	$0.0	$0.0	$0.0	$3.4	511	2
East Frankfort - Crete	Line	ComEd	$3.5	$2.0	$1.4	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	1,490	0
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
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
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
Cloverdale - Lexington	Line	AEP	($6.3)	($4.5)	($0.4)	($2.1)	$0.5	$0.2	$0.1	$0.4	($1.8)	752	335
Bedington - Black Oak	Interface	500	($2.0)	($3.5)	$0.1	$1.6	($0.1)	($0.0)	$0.0	($0.0)	$1.6	395	61

Table 7-41 AEP Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-41)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	($75.9)	($128.5)	$1.5	$54.1	($14.2)	$0.3	$0.3	($14.2)	$39.9	2,182	788
Kammer	Transformer	500	($27.2)	($73.1)	($0.9)	$45.1	($9.5)	$3.2	$0.4	($12.4)	$32.8	2,251	1,261
Mount Storm - Pruntytown	Line	AP	($23.5)	($60.1)	$3.1	$39.6	($9.1)	$0.3	($0.4)	($9.8)	$29.8	1,546	771
Bedington - Black Oak	Interface	500	($20.3)	($44.9)	$1.6	$26.2	($2.1)	$0.8	($0.0)	($2.9)	$23.3	1,361	209
Axton	Transformer	AEP	$2.7	($12.5)	$2.1	$17.3	$0.0	$0.0	$0.0	$0.0	$17.3	418	0
Mount Storm	Transformer	AP	($8.8)	($23.4)	$1.1	$15.7	($5.2)	($1.7)	($0.2)	($3.7)	$12.0	908	460
West	Interface	500	($18.9)	($34.3)	$0.2	$15.6	($3.3)	$0.9	$0.1	($4.0)	$11.6	1,197	372
Cloverdale - Lexington	Line	AEP	($88.6)	($97.5)	($7.0)	$1.9	($15.7)	($4.1)	$0.7	($10.9)	($8.9)	2,941	1,506
Amos	Transformer	AEP	$5.9	($1.6)	$0.2	$7.7	$0.4	$0.6	$0.1	($0.2)	$7.5	31	19
Sammis - Wylie Ridge	Line	AP	($7.8)	($5.2)	$0.1	($2.5)	($3.2)	($0.9)	($1.2)	($3.4)	($5.9)	708	789
Mahans Lane - Tidd	Line	AEP	($1.9)	($4.7)	$2.7	$5.4	$0.1	$0.2	$0.0	($0.0)	$5.4	772	217
Bedington	Transformer	AP	($4.3)	($8.3)	$0.3	$4.3	($0.4)	($0.1)	($0.0)	($0.3)	$3.9	999	234
Central	Interface	500	($6.3)	($9.7)	($0.0)	$3.4	($0.1)	$0.0	($0.0)	($0.1)	$3.3	701	22
Aqueduct - Doubs	Line	AP	($5.5)	($8.6)	$0.1	$3.2	($0.1)	($0.0)	$0.0	($0.1)	$3.2	293	7
Axton - Jacksons Ferry	Line	AEP	$0.5	($2.3)	$0.3	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	83	0

AP Control Zone

Table 7-42 AP Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-42)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
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
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
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
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
Wylie Ridge	Transformer	AP	$6.1	$7.4	$5.4	$4.1	($1.1)	($0.5)	($7.2)	($7.7)	($3.6)	354	335
Bedington - Harmony	Line	AP	$2.0	($0.1)	$0.5	$2.6	$0.0	$0.0	($0.0)	($0.1)	$2.6	262	28
Doubs	Transformer	AP	$2.0	($0.3)	$0.0	$2.4	$0.2	$0.1	($0.1)	$0.0	$2.4	84	30
Cloverdale - Lexington	Line	AEP	$1.2	($1.3)	$0.8	$3.3	($0.1)	$0.0	($0.9)	($1.0)	$2.3	752	335
Carroll - Catoctin	Line	AP	$0.4	$0.0	($0.0)	$0.3	$0.7	($0.8)	$0.2	$1.6	$2.0	99	22
Yukon	Transformer	AP	$2.2	$0.4	$0.0	$1.8	$0.0	$0.2	$0.1	($0.1)	$1.7	142	39
Belmont	Transformer	AP	$3.2	$0.2	$0.6	$3.6	($0.2)	$0.4	($0.1)	($0.7)	$2.9	871	71
West	Interface	500	($12.5)	($15.3)	($2.0)	$0.8	$0.3	$0.2	$0.4	$0.5	$1.3	391	85
Kingwood - Pruntytown	Line	AP	$1.0	($0.1)	($0.0)	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.1	158	7

Table 7-43 AP Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-43)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$14.9	($107.9)	$1.4	$124.2	$2.0	$8.6	$0.3	($6.4)	$117.8	2,182	788
Mount Storm - Pruntytown	Line	AP	($2.8)	($71.7)	$0.3	$69.1	($0.4)	$3.8	($0.2)	($4.4)	$64.7	1,546	771
Bedington - Black Oak	Interface	500	($3.4)	($54.1)	($1.2)	$49.5	$0.5	$0.2	$0.5	$0.8	$50.3	1,361	209
Cloverdale - Lexington	Line	AEP	$20.2	($25.4)	$5.7	$51.3	($3.2)	($0.3)	($7.2)	($10.1)	$41.3	2,941	1,506
Bedington	Transformer	AP	$29.6	($7.2)	$0.9	$37.7	($0.5)	($0.5)	($0.1)	($0.1)	$37.7	999	234
Meadow Brook	Transformer	AP	$28.4	($1.5)	$0.6	$30.5	($3.1)	($0.2)	($0.1)	($3.1)	$27.4	774	173
Mount Storm	Transformer	AP	$1.0	($27.9)	$1.1	$30.0	($2.0)	$2.3	($0.9)	($5.3)	$24.7	908	460
Sammis - Wylie Ridge	Line	AP	$5.3	$3.4	$2.5	$4.4	($5.8)	$1.0	($10.7)	($17.5)	($13.1)	708	789
Kammer	Transformer	500	$23.2	$34.8	$5.5	($6.1)	($3.3)	($2.8)	($4.6)	($5.2)	($11.2)	2,251	1,261
Aqueduct - Doubs	Line	AP	($16.5)	($5.8)	($0.3)	($11.1)	$0.1	$0.1	$0.0	$0.0	($11.0)	293	7
West	Interface	500	($12.4)	($18.0)	($0.1)	$5.6	$2.0	$1.0	$0.7	$1.6	$7.2	1,197	372
Krendale - Seneca	Line	AP	$4.9	($0.4)	$1.6	$6.8	($0.0)	$0.1	($0.0)	($0.1)	$6.8	960	16
Cedar Grove - Roseland	Line	PSEG	$5.3	$1.6	$2.0	$5.7	$0.0	$0.0	$0.3	$0.4	$6.1	627	178
Branchburg - Readington	Line	PSEG	$1.7	($0.2)	$2.7	$4.6	$0.3	$0.1	$0.2	$0.3	$4.9	1,117	271
5004/5005 Interface	Interface	500	($3.2)	($6.9)	$0.0	$3.6	$1.4	$1.1	$0.6	$0.8	$4.5	427	365

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ComEd Control Zone

Table 7-44 ComEd Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-44)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
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
East Frankfort - Crete	Line	ComEd	($14.8)	($29.9)	($0.1)	$15.0	$0.0	$0.0	$0.0	$0.0	$15.0	1,490	0
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
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
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
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
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
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
Wylie Ridge	Transformer	AP	($7.9)	($10.9)	($0.0)	$3.0	($0.8)	($1.5)	$0.0	$0.8	$3.8	354	335
West	Interface	500	($11.4)	($14.9)	($0.0)	$3.5	($0.1)	($0.1)	($0.0)	$0.0	$3.6	391	85
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
Cloverdale - Lexington	Line	AEP	($4.5)	($7.8)	($0.0)	$3.3	($0.6)	($0.3)	$0.0	($0.3)	$3.1	752	335
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

Table 7-45 ComEd Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-45)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Cloverdale - Lexington	Line	AEP	($62.4)	($118.1)	($0.1)	$55.6	($4.6)	($0.5)	($0.2)	($4.2)	$51.4	2,941	1,506
AP South	Interface	500	($77.8)	($117.2)	($0.1)	$39.4	($3.9)	($0.1)	($0.1)	($3.8)	$35.5	2,182	788
Kammer	Transformer	500	($35.9)	($62.2)	($0.1)	$26.2	($4.2)	$3.6	($0.1)	($7.8)	$18.4	2,251	1,261
Bedington - Black Oak	Interface	500	($23.7)	($39.0)	($0.1)	$15.2	$0.0	($0.0)	$0.0	$0.1	$15.3	1,361	209
West	Interface	500	($20.7)	($32.6)	($0.0)	$11.9	($0.2)	($0.6)	($0.0)	$0.4	$12.3	1,197	372
Mount Storm - Pruntytown	Line	AP	($35.1)	($54.2)	($0.1)	$19.0	($6.4)	$1.3	($0.2)	($7.9)	$11.2	1,546	771
East Frankfort - Crete	Line	ComEd	($7.1)	($16.8)	($0.1)	$9.6	$0.0	$0.0	$0.0	$0.0	$9.6	530	0
Burnham - Munster	Line	ComEd	($14.5)	($23.7)	($0.0)	$9.2	($2.6)	($2.6)	($0.5)	($0.5)	$8.7	422	140
Central	Interface	500	($5.5)	($9.9)	($0.0)	$4.3	($0.0)	($0.0)	($0.0)	($0.0)	$4.3	701	22
Axton	Transformer	AEP	($6.9)	($10.9)	($0.0)	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	418	0
Krendale - Seneca	Line	AP	($4.3)	($8.1)	($0.0)	$3.8	$0.0	($0.0)	$0.0	$0.0	$3.9	960	16
Sliver Lake - Cherry Valley	Line	ComEd	$0.1	($3.0)	$0.0	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	97	0
Mount Storm	Transformer	AP	($13.7)	($21.1)	($0.0)	$7.4	($4.0)	$0.4	($0.2)	($4.6)	$2.7	908	460
Cherry Valley	Transformer	ComEd	$1.8	($0.9)	$0.0	$2.7	$0.3	$0.3	($0.0)	$0.0	$2.7	68	88
East	Interface	500	($3.3)	($5.9)	$0.0	$2.6	$0.0	$0.0	($0.0)	$0.0	$2.7	510	9

DAY Control Zone

Table 7-46 DAY Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-46)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
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
West	Interface	500	($0.8)	($1.4)	$0.0	$0.7	$0.0	$0.0	$0.0	($0.0)	$0.7	391	85
Wylie Ridge	Transformer	AP	($0.6)	($1.1)	($0.0)	$0.5	$0.2	$0.2	$0.0	($0.0)	$0.4	354	335
Cloverdale - Lexington	Line	AEP	($0.3)	($0.8)	$0.0	$0.5	$0.0	$0.1	$0.0	($0.1)	$0.4	752	335
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
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
Marquis - Waverly	Line	AEP	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.2	74	14
Elrama - Mitchell	Line	AP	($0.1)	($0.3)	($0.0)	$0.2	$0.1	$0.0	$0.0	$0.1	$0.2	225	184
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
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
Kammer - Ormet	Line	AEP	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	552	509
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	0
Breed - Wheatland	Line	AEP	$0.0	$0.1	$0.0	($0.1)	$0.0	($0.0)	($0.0)	$0.0	($0.1)	511	2

Table 7-47 DAY Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-47)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Cloverdale - Lexington	Line	AEP	($7.8)	($10.0)	$0.1	$2.3	$0.3	($0.7)	$0.0	$1.0	$3.3	2,941	1,506
Kammer	Transformer	500	($4.5)	($5.7)	($0.0)	$1.2	$1.1	$0.1	$0.0	$0.9	$2.1	2,251	1,261
AP South	Interface	500	($8.1)	($10.1)	$0.0	$2.0	$0.4	$0.7	($0.0)	($0.3)	$1.7	2,182	788
Bedington - Black Oak	Interface	500	($2.7)	($4.0)	($0.0)	$1.3	$0.1	$0.3	($0.0)	($0.3)	$1.0	1,361	209
Mount Storm - Pruntytown	Line	AP	($4.3)	($3.6)	$0.0	($0.7)	$0.1	$0.4	($0.0)	($0.3)	($0.9)	1,546	771
West	Interface	500	($2.0)	($3.2)	$0.0	$1.2	$0.2	$0.6	($0.0)	($0.5)	$0.8	1,197	372
5004/5005 Interface	Interface	500	($0.6)	($1.2)	$0.0	$0.5	$0.1	$0.1	($0.0)	$0.0	$0.6	427	365
Sammis - Wylie Ridge	Line	AP	($0.8)	($0.6)	($0.0)	($0.3)	$0.8	($0.1)	($0.2)	$0.7	$0.4	708	789
Central	Interface	500	($0.6)	($1.0)	$0.0	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	701	22
Axton	Transformer	AEP	($0.6)	($1.0)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	418	0
Conemaugh - Keystone	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.3	$0.0	($0.0)	$0.3	$0.3	16	36
Mount Storm	Transformer	AP	($1.7)	($1.3)	$0.0	($0.4)	($0.0)	($0.2)	($0.0)	$0.2	($0.2)	908	460
Axton - Jacksons Ferry	Line	AEP	($0.1)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	83	0
Whitpain	Transformer	PECO	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.2	89	68
Wakefield - Sargents	Line	AEP	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	15	0

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DLCO Control Zone

Table 7-48 DLCO Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-48)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
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
Elrama - Mitchell	Line	AP	($2.7)	($1.8)	($0.0)	($0.9)	($0.2)	$0.9	$0.0	($1.1)	($2.1)	225	184
West	Interface	500	($3.8)	($5.5)	($0.0)	$1.6	($0.1)	$0.0	$0.0	($0.1)	$1.5	391	85
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
Collier	Transformer	DLCO	$1.4	$0.3	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	46	0
Wylie Ridge	Transformer	AP	($8.5)	($12.9)	($0.0)	$4.4	($1.2)	$2.2	$0.0	($3.3)	$1.1	354	335
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
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
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
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	0
Krendale - Seneca	Line	AP	($0.7)	($1.0)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	245	0
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
Cloverdale - Lexington	Line	AEP	($0.7)	($1.1)	$0.0	$0.4	($0.1)	$0.0	($0.0)	($0.1)	$0.3	752	335
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

Table 7-49 DLCO Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-49)

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Sammis - Wylie Ridge	Line	AP	($7.3)	($16.6)	($0.0)	$9.3	($15.0)	$5.9	$0.0	($20.9)	($11.6)	708	789
Bedington - Black Oak	Interface	500	($12.5)	($17.7)	($0.0)	$5.2	($1.0)	$0.6	$0.0	($1.6)	$3.6	1,361	209
AP South	Interface	500	($30.2)	($42.4)	($0.0)	$12.3	($7.1)	$1.6	$0.0	($8.8)	$3.5	2,182	788
Krendale - Seneca	Line	AP	($3.8)	($6.5)	($0.0)	$2.7	($0.1)	$0.0	$0.0	($0.1)	$2.7	960	16
Cheswick - Universal	Line	DLCO	($1.3)	($3.7)	$0.0	$2.4	$0.1	$0.3	($0.0)	($0.2)	$2.3	411	158
Cloverdale - Lexington	Line	AEP	($10.4)	($16.3)	$0.0	$5.9	($2.7)	$0.9	($0.0)	($3.7)	$2.2	2,941	1,506
Mount Storm - Pruntytown	Line	AP	($17.3)	($24.5)	($0.0)	$7.2	($5.6)	$3.3	$0.0	($8.8)	($1.7)	1,546	771
Mount Storm	Transformer	AP	($6.8)	($9.9)	($0.0)	$3.1	($3.1)	$1.7	$0.0	($4.8)	($1.7)	908	460
Beaver - Clinton	Line	DLCO	$0.6	($0.9)	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	140	0
Central	Interface	500	($2.0)	($3.3)	($0.0)	$1.3	($0.1)	$0.0	$0.0	($0.1)	$1.3	701	22
Cheswick - Evergreen	Line	DLCO	$0.4	($1.2)	$0.0	$1.6	($0.2)	$0.4	$0.0	($0.5)	$1.1	85	130
Crescent	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.7	($0.3)	($0.0)	$1.0	$1.0	0	30
5004/5005 Interface	Interface	500	($3.2)	($4.1)	($0.0)	$0.9	($1.3)	$0.6	$0.0	($1.8)	($0.9)	427	365
Krendale - Shanorma	Line	AP	($0.9)	($1.7)	($0.0)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	326	0
Bedington - Harmony	Line	AP	($0.3)	($0.5)	($0.0)	$0.1	($0.6)	$0.3	$0.0	($0.9)	($0.8)	379	360

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-50 Dominion Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-50)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
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
Cloverdale - Lexington	Line	AEP	$5.8	$2.4	$0.9	$4.3	($0.1)	($1.8)	($1.2)	$0.5	$4.8	752	335
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
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
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
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
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
West	Interface	500	($2.4)	($3.3)	$0.0	$1.0	$0.1	$0.2	$0.1	$0.0	$1.0	391	85
Wylie Ridge	Transformer	AP	$2.5	$1.7	$0.4	$1.2	($0.1)	($0.2)	($0.4)	($0.2)	$1.0	354	335
Ox	Transformer	Dominion	$0.8	($0.1)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	8	0
Crozet - Dooms	Line	Dominion	$0.7	($0.3)	$0.0	$1.0	($0.3)	($0.2)	($0.0)	($0.1)	$0.9	54	37
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
Chickahominy - Lanexa	Line	Dominion	$0.5	($0.0)	$0.0	$0.6	($0.1)	($0.3)	$0.0	$0.1	$0.7	42	19
Clover - Farmville	Line	Dominion	($0.0)	($0.7)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	41	0
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

Table 7-51 Dominion Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-51)

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$63.8	($78.6)	$3.9	$146.3	$5.7	$7.3	($2.9)	($4.4)	$141.8	2,182	788
Cloverdale - Lexington	Line	AEP	$103.2	$42.7	$12.3	$72.8	$0.0	($5.7)	($9.4)	($3.7)	$69.1	2,941	1,506
Bedington - Black Oak	Interface	500	$32.0	$17.2	$2.2	$17.0	$0.2	($0.8)	($0.5)	$0.5	$17.5	1,361	209
Mount Storm	Transformer	AP	$21.0	$8.7	$4.1	$16.4	($8.8)	$16.4	($4.3)	($29.5)	($13.1)	908	460
Aqueduct - Doubs	Line	AP	$9.1	($2.7)	$0.2	$12.0	$0.0	($0.0)	($0.0)	$0.0	$12.0	293	7
Bristers - Ox	Line	Dominion	($1.2)	($12.4)	($0.6)	$10.7	$0.8	$1.1	$0.4	$0.1	$10.8	77	38
Meadow Brook	Transformer	AP	($0.7)	($6.8)	($0.0)	$6.1	($0.1)	$0.3	$0.1	($0.3)	$5.8	774	173
Kammer	Transformer	500	$14.5	$12.6	$1.9	$3.8	($0.2)	($2.9)	($1.6)	$1.1	$4.9	2,251	1,261
Dickerson - Pleasant View	Line	Pepco	($6.8)	($2.9)	($0.1)	($4.0)	($0.1)	$0.7	$0.1	($0.7)	($4.8)	468	124
Mount Storm - Pruntytown	Line	AP	$47.0	$51.9	$5.8	$0.9	($4.3)	($14.7)	($6.6)	$3.7	$4.6	1,546	771
Danville - East Danville	Line	Dominion	$4.5	$1.8	$0.2	$3.0	($0.2)	($0.2)	$0.3	$0.3	$3.3	646	147
Pleasantville - Ashburn	Line	Dominion	$3.2	$0.2	$0.0	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	10	0
East	Interface	500	($4.6)	($2.2)	($0.4)	($2.8)	$0.0	$0.0	$0.0	($0.0)	($2.8)	510	9
West	Interface	500	($11.6)	($9.2)	$0.1	($2.3)	$0.4	$0.9	$0.1	($0.4)	($2.6)	1,197	372
Central	Interface	500	($5.6)	($3.1)	($0.1)	($2.6)	($0.0)	$0.0	$0.0	($0.0)	($2.6)	701	22

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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 *2009 Quarterly State of the Market Report for PJM: January through September* focuses on the annual ARR allocations, the Annual FTR Auctions and the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2008 to 2009 planning period which covers June 1, 2008, through May 31, 2009, and the 2009 to 2010 planning period which covers June 1, 2009, through May 31, 2010.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability. PJM also runs a Long Term FTR Auction for the three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. The second Long Term FTR Auction is being conducted during the 2009 to 2010 planning period and covers three consecutive planning periods between 2010 and 2013. The 2010 to 2013 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 Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2009 to 2010 planning period include the AP South Interface and the Mahans Lane — Tidd line.[2] Market participants can also sell FTRs. In the Annual FTR Auction for the 2009 to 2010 planning period, total FTR sell offers

1 87 FERC ¶ 61,054 (1999).

2 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones. Four of these, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion, were eligible for direct allocation FTRs during the 2006 to 2007 planning period, but not the 2007 to 2008, the 2008 to 2009 or the 2009 to 2010 planning period. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2008 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

were 142,154 MW, up from 83,453 MW during the 2008 to 2009 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first four months (June through September 2009) of the 2009 to 2010 planning period, there were 1,292,896 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the Annual FTR Auction for the 2009 to 2010 planning period, total FTR buy bids were 1,436,335 MW, down from 2,181,273 MW during the 2008 to 2009 planning period. Total FTR self scheduled bids were 68,589 MW for the 2009 to 2010 planning period, a decrease from 72,851 MW for the 2008 to 2009 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first four months (June through September 2009) of the 2009 to 2010 planning period, total FTR buy bids were 3,124,431 MW.

- **FTR Credit Issues.** While no participants defaulted in the first nine months of 2009, one participant had losses on annual FTRs that extended into 2009. PJM made multiple filings in 2008 and 2009 to reform its credit policies, focusing particularly on ensuring an appropriate level of credit to cover positions acquired by market participants in counter flow FTRs. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[3] These continue to be investigated. On April 3, 2009, the FERC conditionally approved the second in a series of filings by PJM aimed at reform of its credit policies.[4] Effective June 1, 2009, PJM performs weekly rather than monthly billing and payment for the majority of invoice line items, reduced the Unsecured Credit Allowance by two-thirds, eliminated the Unsecured Credit Allowance in support of trading in FTRs, and implemented procedures that allow it to close out and liquidate forward FTR positions held by Market Participants who have defaulted on their obligations.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2009 to 2010 Annual FTR Auction was low to moderate for FTR obligations and 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 provide additional information about the ownership of prevailing flow and counter flow FTRs, the Market Monitoring Unit (MMU) categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. During the 2009 to 2010 planning period, physical entities own two thirds of prevailing flow Annual FTRs while financial entities own more than half of counter flow Annual FTRs. Overall, financial entities own about 38 percent of all Annual FTRs. Financial entities own about 71 percent of prevailing flow and 81 percent of counter flow Monthly Balance of Planning Period FTRs from January 2009 through September 2009. Overall, financial entities own about 75 percent of all Monthly Balance of Planning Period FTRs.

Market Performance

- **Volume.** For the 2009 to 2010 planning period, the Annual FTR Auction cleared 155,612 MW (10.8 percent) of FTR buy bids, down from 204,349 MW (9.4 percent of demand) for the 2008 to 2009 planning period. The Annual FTR Auction also cleared 7,399 MW (5.2 percent) of FTR sell offers for the 2009 to 2010 planning period, up from 4,534 MW (5.4 percent) for the 2008 to 2009 planning period. For the first four months of the 2009 to 2010 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 305,678 MW (9.8 percent) of FTR buy bids and 112,608 MW (8.7 percent) of FTR sell offers.

- **Price.** For the 2009 to 2010 planning period, 83.2 percent of the Annual FTRs were purchased for less than $1 per MWh and 90.6 percent for less than $2 per MWh. For the 2009 to 2010 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.66 per MWh for 24-hour FTRs, $0.57 per MWh for on peak FTRs and $0.40 per MWh for off peak FTRs. Comparable, weighted-average prices paid for annual buy-bid FTR obligations for the 2008 to 2009 planning period were $1.96 per MWh for 24-hour FTRs and $0.55 per MWh for on peak FTRs and $0.26 per MWh for off peak FTRs. The weighted-average prices paid for 2009 to 2010 planning period annual buy-bid FTR obligations and options were $0.53 per MWh and $0.35 per MWh, respectively, compared to $0.69 per MWh and $0.24 per MWh, respectively, in the 2008 to 2009 planning period.[5] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning

3 PJM Interconnection, L.L.C. made a filing under section 205 of the Federal Power Act to amend section 15.2 of the PJM Operating Agreement concerning defaults on short FTR portfolios in Docket No. ER08-455-000, (January 18, 2008).

4 127 FERC ¶61,017. The FERC has approved PJM's proposed revisions to its credit policy in Docket No. ER08-376-000. 122 FERC ¶61,279 (2008). PJM has notified the Commission of its intent to file in 2009 an additional proposal that will provide "clarification and definition of the commercial and legal relationship of PJM to its market participants in context of both pool and non-pool transactions. 127 FERC ¶61,017 at P 3.

5 Weighted-average prices for FTRs in the Long Term FTR Auction, Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak. For example, FTRs in the 2009 to 2010 Annual FTR Auction would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,096 hours) and off peak (4,664 hours).

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Period FTR Auctions for the first four months of the 2009 to 2010 planning period was $0.24 per MWh, compared with $0.30 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2008 to 2009 planning period.

- **Revenue.** The Annual FTR Auction generated $1,329.8 million of net revenue for all FTRs during the 2009 to 2010 planning period, down from $2,422.6 million for the 2008 to 2009 planning period. The Monthly Balance of Planning Period FTR Auctions generated $8.8 million in net revenue for all FTRs during the first four months of the 2009 to 2010 planning period.

- **Revenue Adequacy.** FTRs were 100 percent revenue adequate for the 2008 to 2009 planning period. FTRs were paid at 96 percent of the target allocation level for the first four months of the 2009 to 2010 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $199.7 million of FTR revenues during the first four months of the 2009 to 2010 planning period and $1,748.3 million during the 2008 to 2009 planning period. For the first four months of the 2009 to 2010 planning period, the top sink and top source with the highest positive FTR target allocations were the AEP west of Mon Power aggregate and the Mount Storm buses, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations were Midwest ISO and the Western Hub, respectively.

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2009 to 2010 planning period were the AP South Interface and the Electric Junction — Frontenac line. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- **Demand.** Total demand in the annual ARR allocation was 140,037 MW for the 2009 to 2010 planning period with 64,987 MW bid in Stage 1A, 26,517 MW bid in Stage 1B and 48,533 MW bid in Stage 2. This is down from 140,668 MW for the 2008 to 2009 planning period with 64,546 MW bid in Stage 1A, 27,291 MW bid in Stage 1B and 48,831 MW bid in Stage 2. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 6,100 MW of ARRs associated with approximately $115,500 per MW-day of revenue that were reassigned in the first four months of the 2009 to 2010 planning period. There were 15,326 MW of ARRs associated with approximately $533,900 per MW-day of revenue that were reassigned for the full 2008 to 2009 planning period.

Market Performance

- **Volume.** Of 140,037 MW in ARR requests for the 2009 to 2010 planning period, 109,413 MW (78.1 percent) were allocated. There were 64,913 MW allocated in Stage 1A, 26,514 MW allocated in Stage 1B and 17,986 MW allocated in Stage 2. Eligible market participants self scheduled 68,589 MW (62.7 percent) of these allocated ARRs as Annual FTRs. Of 140,668 MW in ARR requests for the 2008 to 2009 planning period, 112,011 MW (79.6 percent) were allocated. There were 64,520 MW allocated in Stage 1A, 26,685 MW allocated in Stage 1B and 20,806 MW allocated in Stage 2. Eligible market participants self scheduled 72,851 MW (65.0 percent) of these allocated ARRs as Annual FTRs.

- **Revenue.** As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

- **Revenue Adequacy.** During the 2009 to 2010 planning period, ARR holders will receive $1,273.5 million in ARR credits, with an average hourly ARR credit of $1.33 per MWh. During the 2009 to 2010 planning period, the ARR target allocations were $1,273.5 million while PJM collected $1,338.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through September 2009, making ARRs revenue adequate. During the 2008 to 2009 planning period, ARR holders received $2,361.3 million in ARR credits, with an average hourly ARR credit of $2.41 per MWh. For the 2008 to 2009 planning period, the ARR target allocations were $2,361.3 million while PJM collected $2,489.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** When ARRs were allocated for the 2009 to 2010 planning period, some of the requested ARRs were prorated in Stage 2 as a result of binding transmission constraints. No ARRs were prorated in Stage 1A and Stage 1B since there were no constraints affecting the ARR allocation in these two stages. For the 2008 to 2009 planning period, no ARRs were prorated in Stage 1A of the annual ARR allocation. In Stage 1B, the only constraint affecting the ARR allocation was the Cedar Grove — Clifton line. There were 605.4 MW of Stage 1B ARRs denied to participants whose requested ARRs affected that binding transmission constraint.

- **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 2008 to 2009 planning period, all ARRs and FTRs hedged more than 100 percent of the congestion costs within PJM. During the first four months of the 2009 to 2010 planning period, total ARR and FTR revenues hedged 92.1 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 3.5 percent of the total real time energy charges for the first three quarters of 2009.

  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 minus 1.0 percent of the total real time energy charges for the first three quarters of 2009 because the purchase cost exceeded the value of the credits. When combined, the sum is a measure of the total value of ARRs plus FTRs. The total value of ARRs plus FTRs was 2.5 percent of the total real time energy charges for the first three quarters of 2009.

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 2009 to 2010 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs. The MMU recommends that the rules for ARR reassignment when load shifts should address the fact that in the case of ARRs self scheduled as FTRs, the underlying FTRs do not follow the load while the ARRs do.

ARRs were 100 percent revenue adequate for both the 2008 to 2009 and the 2009 to 2010 planning periods. FTRs were paid at 100 percent of the target allocation level for the 12-month period of the 2008 to 2009 planning period, and at 96 percent of the target allocation level for the first four months of the 2009 to 2010 planning period. Revenue adequacy for a planning period is not final until the end of the period.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.

The total of ARR and FTR revenues hedged more than 100 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2008 to 2009 planning period and 92.1

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percent of the congestion costs in PJM for the first four months of the 2009 to 2010 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

Financial Transmission Rights

Patterns of Ownership

Table 8-1 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September 2009 (See 2008 SOM Table 8-5)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	28.8%	19.2%	24.8%
Financial	71.2%	80.8%	75.2%
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 2009 (See 2008 SOM Table 8-9)

Monthly Auction Requested	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-09	Obligations	Buy bids	166,943	648,482	59,472	9.2%	589,011	90.8%
		Sell offers	36,552	172,413	17,489	10.1%	154,924	89.9%
	Options	Buy bids	473	25,043	3,628	14.5%	21,415	85.5%
		Sell offers	475	13,010	1,871	14.4%	11,139	85.6%
Feb-09	Obligations	Buy bids	167,297	613,252	54,064	8.8%	559,188	91.2%
		Sell offers	33,278	135,132	13,663	10.1%	121,469	89.9%
	Options	Buy bids	1,000	26,021	1,408	5.4%	24,613	94.6%
		Sell offers	399	11,925	1,370	11.5%	10,555	88.5%
Mar-09	Obligations	Buy bids	153,613	542,094	54,409	10.0%	487,685	90.0%
		Sell offers	43,579	176,838	14,931	8.4%	161,907	91.6%
	Options	Buy bids	738	38,982	4,626	11.9%	34,356	88.1%
		Sell offers	472	12,300	1,382	11.2%	10,918	88.8%
Apr-09	Obligations	Buy bids	121,034	417,636	49,603	11.9%	368,034	88.1%
		Sell offers	31,574	131,945	12,924	9.8%	119,021	90.2%
	Options	Buy bids	204	22,992	614	2.7%	22,379	97.3%
		Sell offers	353	8,776	1,607	18.3%	7,168	81.7%
May-09	Obligations	Buy bids	79,272	285,448	31,020	10.9%	254,428	89.1%
		Sell offers	19,030	70,521	8,843	12.5%	61,678	87.5%
	Options	Buy bids	131	9,750	183	1.9%	9,567	98.1%
		Sell offers	195	2,585	1,345	52.0%	1,240	48.0%
Jun-09	Obligations	Buy bids	202,097	807,023	72,951	9.0%	734,073	91.0%
		Sell offers	79,699	276,795	24,514	8.9%	252,281	91.1%
	Options	Buy bids	734	40,968	2,552	6.2%	38,416	93.8%
		Sell offers	5,377	69,781	11,567	16.6%	58,214	83.4%
Jul-09	Obligations	Buy bids	196,831	802,217	67,977	8.5%	734,240	91.5%
		Sell offers	79,359	300,588	22,533	7.5%	278,055	92.5%
	Options	Buy bids	547	47,525	2,954	6.2%	44,570	93.8%
		Sell offers	4,264	60,406	7,011	11.6%	53,396	88.4%
Aug-09	Obligations	Buy bids	202,379	702,162	76,065	10.8%	626,096	89.2%
		Sell offers	70,434	245,516	17,981	7.3%	227,535	92.7%
	Options	Buy bids	101	6,290	1,287	20.5%	5,003	79.5%
		Sell offers	3,264	48,784	4,111	8.4%	44,673	91.6%
Sep-09	Obligations	Buy bids	173,626	681,422	79,711	11.7%	601,711	88.3%
		Sell offers	67,180	237,135	18,347	7.7%	218,788	92.3%
	Options	Buy bids	474	36,824	2,180	5.9%	34,644	94.1%
		Sell offers	3,565	53,891	6,546	12.1%	47,345	87.9%
2008/2009*	Obligations	Buy bids	2,143,034	9,449,644	782,007	8.3%	8,667,637	91.7%
		Sell offers	504,152	1,991,496	226,544	11.4%	1,764,952	88.6%
	Options	Buy bids	11,754	773,793	22,209	2.9%	751,584	97.1%
		Sell offers	6,550	180,904	32,203	17.8%	148,701	82.2%
2009/2010*	Obligations	Buy bids	774,933	2,992,824	296,704	9.9%	2,696,120	90.1%
		Sell offers	296,672	1,060,034	83,374	7.9%	976,660	92.1%
	Options	Buy bids	1,856	131,606	8,974	6.8%	122,633	93.2%
		Sell offers	16,470	232,862	29,234	12.6%	203,628	87.4%

* Shows twelve months for 2008/2009 and four months ended 30-Sep-2009 for 2009/2010

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Table 8-3 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January through September 2009 (See 2008 SOM Table 8-10)

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-09	Bid	299,268	129,139	99,968				145,151	673,525
	Cleared	41,932	9,425	3,985				7,758	63,100
Feb-09	Bid	311,274	106,999	93,220				127,781	639,274
	Cleared	37,183	6,216	5,347				6,727	55,472
Mar-09	Bid	305,146	120,085	115,103				40,741	581,075
	Cleared	41,859	8,073	6,687				2,415	59,034
Apr-09	Bid	306,763	133,866						440,629
	Cleared	41,884	8,332						50,216
May-09	Bid	295,198							295,198
	Cleared	31,204							31,204
Jun-09	Bid	283,451	121,774	119,403	24,320	104,418	102,266	92,358	847,992
	Cleared	33,822	9,100	8,599	2,500	7,967	7,524	5,991	75,503
Jul-09	Bid	306,644	133,812	95,573		100,333	107,062	106,318	849,742
	Cleared	38,785	8,346	3,991		5,869	6,325	7,615	70,932
Aug-09	Bid	314,301	85,842	75,477		69,309	79,140	84,383	708,452
	Cleared	47,960	6,627	6,057		4,214	5,276	7,219	77,353
Sep-09	Bid	342,826	89,939	86,533		22,245	90,764	85,939	718,246
	Cleared	52,579	7,095	6,539		2,150	6,268	7,260	81,891

Table 8-4 Secondary bilateral FTR market volume: Planning periods 2008 to 2009 and 2009 to 2010[6] (See 2008 SOM Table 8-11)

Planning Period	Hedge Type	Class Type	Secondary (MW)
2008/2009	Obligation	24-Hour	800
		On Peak	1,133
		Off Peak	9
		Total	1,942
	Option	24-Hour	0
		On Peak	6
		Off Peak	0
		Total	6
2009/2010*	Obligation	24-Hour	1,438
		On Peak	0
		Off Peak	125
		Total	1,563

* Shows four months ended 30-Sep-2009

6 The 2009 to 2010 planning period covers the 2009 to 2010 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through September 30, 2009.

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 2009 (See 2008 SOM Table 8-14)

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-09	$0.08	$0.18	$0.24				$0.04	$0.09
Feb-09	$0.10	$0.28	$0.21				$0.21	$0.16
Mar-09	$0.11	$0.25	$0.17				$0.55	$0.18
Apr-09	$0.12	$0.24						$0.14
May-09	$0.09							$0.09
Jun-09	$0.17	$0.25	$0.17	$1.16	$0.37	$0.48	$0.46	$0.38
Jul-09	$0.17	$0.40	$0.17		$0.25	$0.31	$0.23	$0.24
Aug-09	$0.06	$0.15	$0.19		$0.16	$0.15	$0.16	$0.12
Sep-09	$0.12	$0.28	$0.23		$0.10	$0.37	$0.34	$0.22

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Figure 8-1 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-7)

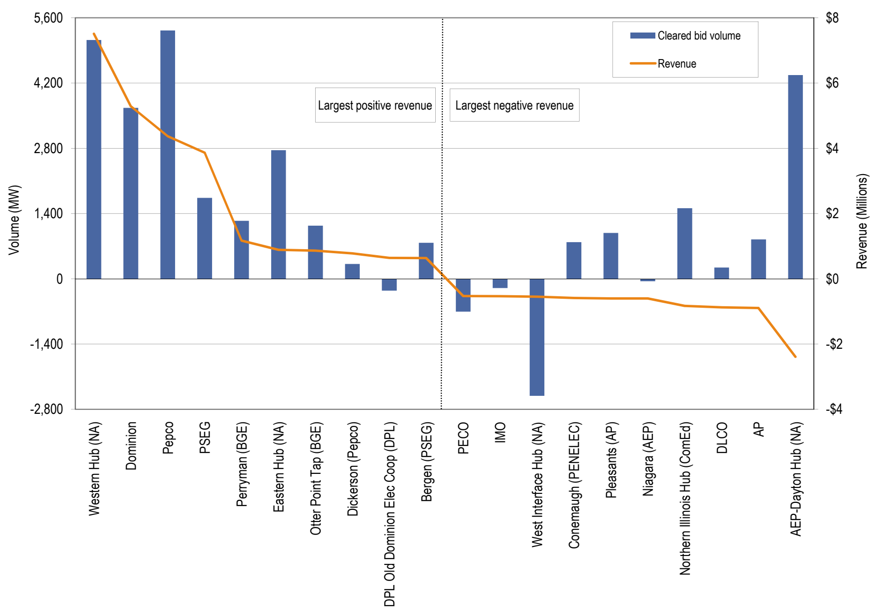

Figure 8-2 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-8)

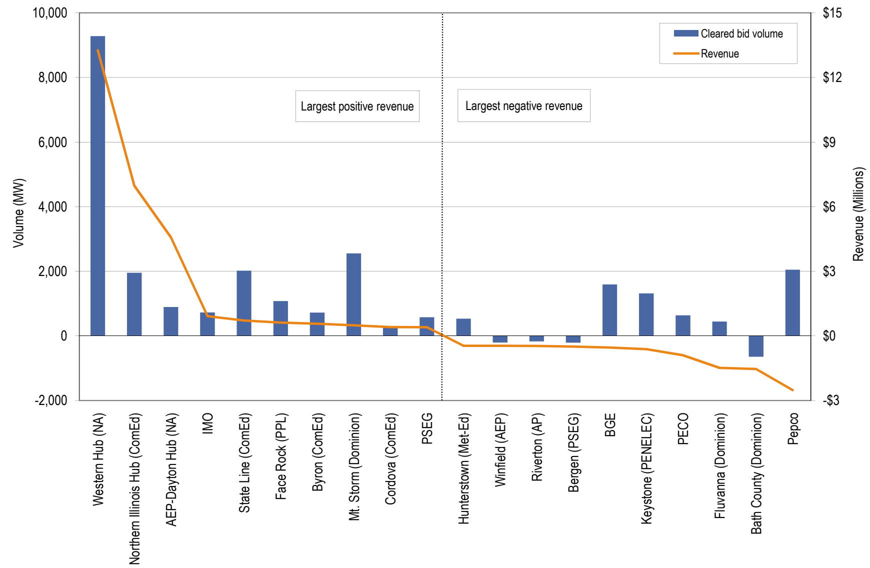

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Table 8-6 Monthly Balance of Planning Period FTR Auction revenue: January through September 2009 (See 2008 SOM Table 8-17)

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-09	Obligations	Buy bids	$1,207,292	$934,011	$244,584	$2,385,888
		Sell offers	$248,591	$573,963	$77,911	$900,466
	Options	Buy bids	$26,505	$140,359	$145,245	$312,108
		Sell offers	$0	$203,453	$129,447	$332,900
Feb-09	Obligations	Buy bids	($83,145)	$2,193,269	$1,332,926	$3,443,050
		Sell offers	$413,446	$1,442,454	$530,041	$2,385,941
	Options	Buy bids	$31,233	$278,934	$178,062	$488,229
		Sell offers	$0	$193,821	$118,916	$312,737
Mar-09	Obligations	Buy bids	$395,276	$2,107,188	$1,467,981	$3,970,446
		Sell offers	$308,687	$1,724,949	$1,167,153	$3,200,789
	Options	Buy bids	$34,097	$435,416	$54,453	$523,967
		Sell offers	$0	$181,733	$52,487	$234,221
Apr-09	Obligations	Buy bids	($223,411)	$1,471,041	$1,062,859	$2,310,489
		Sell offers	$19,324	$954,279	$602,223	$1,575,826
	Options	Buy bids	$1,511	$291,731	$15,883	$309,126
		Sell offers	$0	$260,520	$67,733	$328,253
May-09	Obligations	Buy bids	($234,075)	$902,305	$371,453	$1,039,683
		Sell offers	($12,927)	$429,537	$118,031	$534,641
	Options	Buy bids	$0	$10,099	$8,754	$18,854
		Sell offers	$1,336	$115,521	$48,174	$165,031
Jun-09	Obligations	Buy bids	($455,827)	$9,859,792	$7,471,308	$16,875,272
		Sell offers	$940,697	$4,742,041	$3,783,072	$9,465,811
	Options	Buy bids	$0	$454,961	$67,016	$521,977
		Sell offers	$21,245	$3,150,642	$1,819,405	$4,991,291
Jul-09	Obligations	Buy bids	$415,277	$4,786,066	$4,229,832	$9,431,174
		Sell offers	($59,890)	$2,992,345	$2,645,320	$5,577,775
	Options	Buy bids	$25,700	$221,441	$78,308	$325,449
		Sell offers	$1,231	$959,249	$766,196	$1,726,677
Aug-09	Obligations	Buy bids	$300,985	$2,594,442	$1,835,069	$4,730,497
		Sell offers	($35,209)	$1,385,079	$1,265,654	$2,615,525
	Options	Buy bids	$0	$151,123	$3,931	$155,054
		Sell offers	$130	$512,880	$284,359	$797,368
Sep-09	Obligations	Buy bids	$1,017,942	$4,713,934	$3,266,091	$8,997,967
		Sell offers	$453,760	$3,108,304	$2,190,037	$5,752,101
	Options	Buy bids	$42,397	$103,279	$85,804	$231,480
		Sell offers	$2,554	$1,000,222	$537,203	$1,539,979
2008/2009*	Obligations	Buy bids	$18,536,366	$62,983,127	$39,113,790	$120,633,283
		Sell offers	$10,238,514	$20,746,786	$12,003,977	$42,989,277
	Options	Buy bids	$164,213	$5,175,296	$2,995,811	$8,335,320
		Sell offers	$26,515	$13,614,983	$5,286,634	$18,928,133
2009/2010*	Obligations	Buy bids	$1,278,377	$21,954,234	$16,802,299	$40,034,910
		Sell offers	$1,299,358	$12,227,769	$9,884,084	$23,411,211
	Options	Buy bids	$68,097	$930,803	$235,060	$1,233,960
		Sell offers	$25,160	$5,622,993	$3,407,163	$9,055,315

* Shows twelve months for 2008/2009 and four months ended 30-Sep-2009 for 2009/2010

Revenue Adequacy

Table 8-7 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-18)

Accounting Element	2008/2009	2009/2010*
ARR information		
ARR target allocations	$2,361.3	$426.0
FTR auction revenue	$2,489.6	$454.9
ARR excess	$128.3	$28.9
FTR targets		
FTR target allocations	$1,747.9	$208.3
Adjustments:		
Adjustments to FTR target allocations	($4.1)	($0.1)
Total FTR targets	$1,743.8	$208.2
FTR revenues		
ARR excess	$128.3	$28.9
Competing uses	$0.7	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($59.0)	($14.8)
Hourly congestion revenue	$1,735.7	$200.3
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($52.3)	($14.2)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($3.1)	($0.3)
Adjustments:		
Excess revenues carried forward into future months	$36.8	$23.5
Excess revenues distributed back to previous months	$16.1	$0.0
Other adjustments to FTR revenues	($2.0)	$0.0
Total FTR revenues	$1,801.2	$223.2
Excess revenues distributed to other months	($30.0)	($23.5)
Excess revenues distributed to CEPSW for end-of-year distribution	$0.5	$0.0
Excess revenues distributed to FTR holders	$4.0	$0.0
Total FTR congestion credits	$1,743.8	$199.7
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,751.4	$200.0
Remaining deficiency	$0.0	$8.5

* Shows four months ended 30-Sep-09

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Table 8-8 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-19)

Period	FTR Revenues	FTR Target Allocations	FTR Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Jun-08	$436.9	$432.3	$432.3	100%	$0	$4.7
Jul-08	$371.4	$364.2	$364.2	100%	$0	$7.2
Aug-08	$140.5	$125.0	$125.0	100%	$0	$15.4
Sep-08	$154.6	$154.6	$154.6	100%	$0	$0.0
Oct-08	$109.4	$109.4	$109.4	100%	$0	$0.0
Nov-08	$97.2	$97.2	$97.2	100%	$0	$0.0
Dec-08	$85.3	$77.6	$77.6	100%	$0	$7.7
Jan-09	$159.5	$151.1	$151.1	100%	$0	$8.4
Feb-09	$92.0	$84.3	$84.3	100%	$0	$7.7
Mar-09	$86.7	$86.7	$86.7	100%	$0	$0.0
Apr-09	$32.8	$31.1	$31.1	100%	$0	$1.7
May-09	$34.8	$30.3	$30.3	100%	$0	$4.5
Summary for Planning Period 2008 to 2009						
Total	$1,748.3	$1,743.8	$1,743.8	100%	$0	$4.5
Jun-09	$54.6	$43.9	$43.9	100%	$0	$10.7
Jul-09	$53.2	$40.4	$40.4	100%	$0	$12.8
Aug-09	$87.9	$92.4	$87.9	95.1%	$4.5	$0.0
Sep-09	$27.5	$31.5	$27.5	87.4%	$4.0	$0.0
Summary for Planning Period 2009 to 2010 through Sep 30, 2009						
Total	$199.7	$208.2	$199.7	95.9%	$8.5	$0.0

Figure 8-3 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-9)

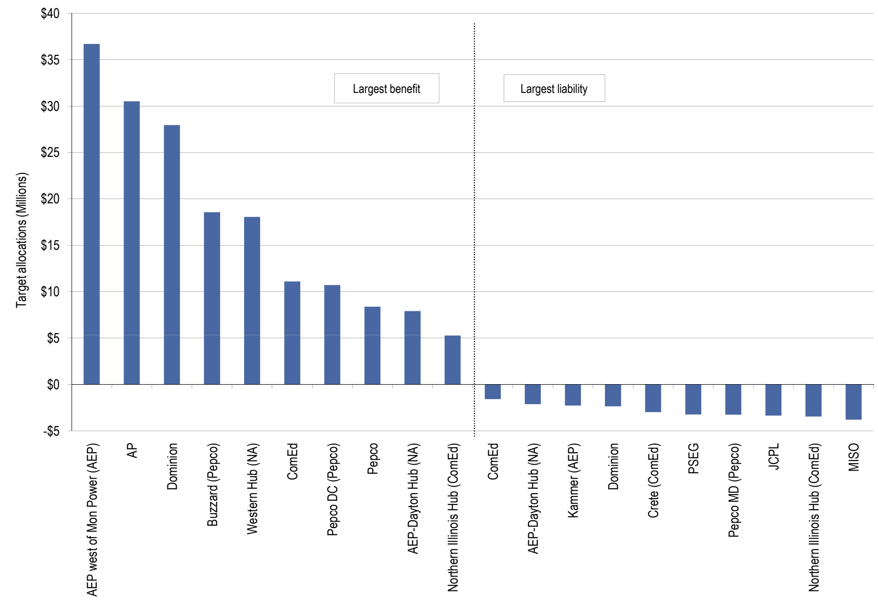
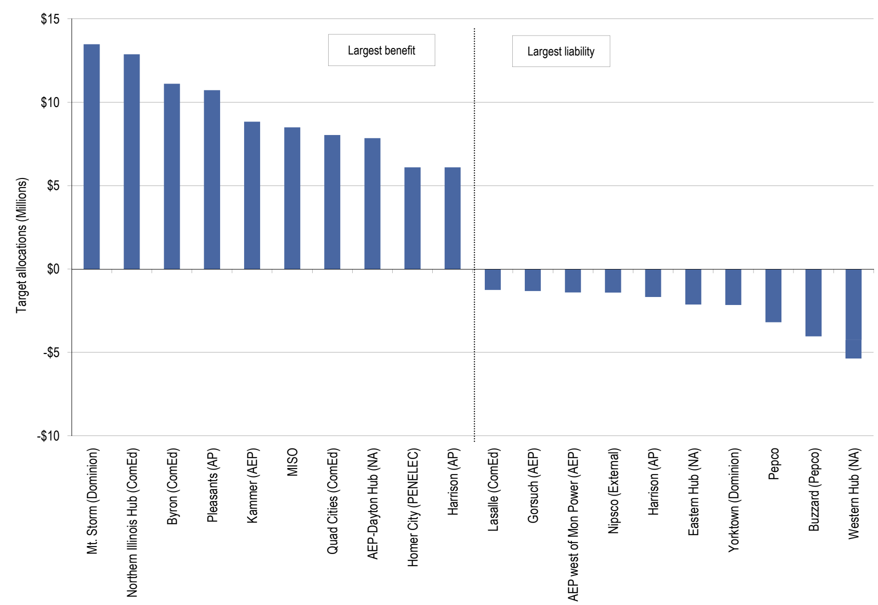


Figure 8-4 Ten largest positive and negative FTR target allocations summed by source: Planning period 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-10)



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, 2008, through September 30, 2009 (See 2008 SOM Table 8-22)

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2008/2009 (12 months)	2009/2010 (4 months)*	2008/2009 (12 months)	2009/2010 (4 months)*
AECO	501	297	$16.1	$5.5
AEP	11	241	$0.2	$5.7
AP	707	232	$164.7	$26.8
BGE	3,361	1,025	$124.3	$21.3
ComEd	3,074	1,086	$10.0	$3.3
DAY	1	0	$0.0	$0.0
DLCO	471	136	$2.1	$0.4
Dominion	5	0	$0.4	$0.0
DPL	1,404	385	$24.8	$4.3
JCPL	1,094	714	$45.0	$10.8
Met-Ed	0	0	$0.0	$0.0
PECO	47	15	$1.4	$0.2
PENELEC	0	0	$0.0	$0.0
Pepco	3,040	721	$79.9	$7.3
PPL	35	19	$2.2	$0.5
PSEG	1,537	1,188	$62.7	$29.5
RECO	40	40	$0.0	$0.0
Total	15,326	6,100	$533.9	$115.5

* Through 30-Sep-09

Market Performance

Revenue Adequacy

Table 8-10 ARR revenue adequacy (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-24)

	2008/2009	2009/2010
Total FTR auction net revenue	$2,489.6	$1,338.6
Annual FTR Auction net revenue	$2,422.6	$1,329.8
Monthly Balance of Planning Period FTR Auction net revenue*	$67.1	$8.8
ARR target allocations	$2,361.3	$1,273.5
ARR credits	$2,361.3	$1,273.5
Surplus auction revenue	$128.3	$65.1
ARR payout ratio	100%	100%
FTR payout ratio*	100%	95.9%

* Shows twelve months for 2008/2009 and four months ended 30-Sep-09 for 2009/2010

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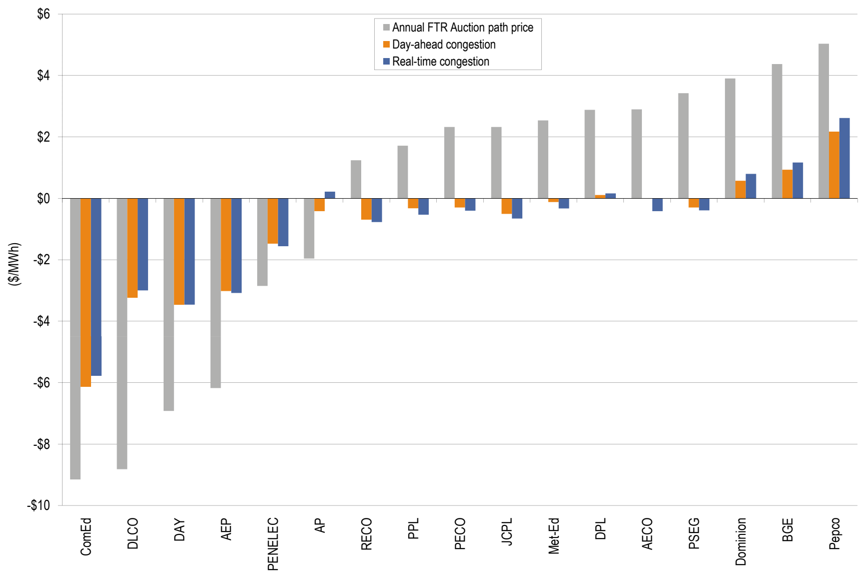
ARR and FTR Revenue and Congestion

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 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-11)



Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-11 ARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-28)

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2008/2009	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,489,647,665	$130,237,257	>100%
2009/2010*	$426,023,336	$199,335,975	$454,904,797	$170,454,514	$185,175,292	($14,720,777)	92.1%

* Shows four months ended 30-Sep-09

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

The hedge provided by ARRs and self scheduled FTRs 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 direct measure of the net price of energy rather than a comparison of the ARR/FTR credits to an accounting measure of congestion. This is a measure of the value of the hedge against real time energy costs provided by ARRs received by loads during this period. Table 8-12 shows the results of this measure by control zone for January through September 2009. As an example, Table 8-12 shows the total value of ARR and self-scheduled FTR credits in the AP Control Zone was $152 million, which was 10.9 percent of the $1.4 billion in total real time energy charges in the AP Control Zone.

Table 8-12 ARRs and self-scheduled FTR credits as a hedge against energy charges by control zone: January through September, 2009 (New Table)

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	$16,055,257	$394,215	$16,449,472	$362,531,281	4.5%
AEP	$2,886,158	$123,796,031	$126,682,189	$3,430,853,351	3.7%
AP	$36,005,367	$115,659,090	$151,664,456	$1,391,655,720	10.9%
BGE	$54,101,786	$899,680	$55,001,467	$1,125,948,483	4.9%
ComEd	$11,396,285	$21,666,115	$33,062,400	$2,210,306,347	1.5%
DAY	$5,944,120	$515,919	$6,460,039	$441,017,205	1.5%
DLCO	$2,759,934	$838	$2,760,772	$352,284,804	0.8%
Dominion	$4,942,139	$73,090,075	$78,032,214	$3,052,779,315	2.6%
DPL	$15,614,464	$896,243	$16,510,707	$622,709,476	2.7%
JCPL	$36,064,022	$1,892,054	$37,956,077	$760,753,914	5.0%
Met-Ed	$127,750	$7,691,384	$7,819,134	$483,838,555	1.6%
PECO	$2,439,977	$10,854,527	$13,294,503	$1,302,980,204	1.0%
PENELEC	$27,957,938	$7,907,489	$35,865,428	$483,763,924	7.4%
Pepco	$31,422,818	$741,863	$32,164,682	$1,079,848,058	3.0%
External	$8,215,938	($9,032,064)	($816,126)	NA	NA
PPL	$1,115,198	$9,035,012	$10,150,211	$1,290,220,318	0.8%
PSEG	$77,531,006	$4,413,611	$81,944,617	$1,475,006,871	5.6%
RECO	($13,856)	$0	($13,856)	$47,469,825	(0.0%)
Total	$334,566,301	$370,422,084	$704,988,384	$19,946,740,011	3.5%

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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. This is a direct measure of the net price of energy rather than a comparison of the FTR credits to an accounting measure of congestion. This is a measure of the value of the hedge against real time energy costs provided by FTRs purchased for this period. Table 8-13 shows the results of this measure by control zone for January through September 2009. When the purchase cost of the FTRs exceeds the FTR credits, the hedge is negative.

Table 8-13 FTRs as a hedge against energy charges by control zone: January through September, 2009 (New Table)

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	$5,524,630	$18,873,817	($13,349,187)	$362,531,281	(3.7%)
AEP	$10,013,903	($35,087,598)	$45,101,500	$3,430,853,351	1.3%
AP	$19,779,699	$30,818,684	($11,038,985)	$1,391,655,720	(0.8%)
BGE	$15,105,748	$32,326,803	($17,221,055)	$1,125,948,483	(1.5%)
ComEd	($5,289,388)	($9,586,391)	$4,297,003	$2,210,306,347	0.2%
DAY	$1,452,915	($1,474,373)	$2,927,288	$441,017,205	0.7%
DLCO	($2,513,610)	($8,951,850)	$6,438,240	$352,284,804	1.8%
Dominion	$19,697,570	$39,643,409	($19,945,840)	$3,052,779,315	(0.7%)
DPL	$12,932,046	$24,995,329	($12,063,284)	$622,709,476	(1.9%)
JCPL	$2,113,718	$42,364,842	($40,251,125)	$760,753,914	(5.3%)
Met-Ed	$2,370,888	$5,871,078	($3,500,190)	$483,838,555	(0.7%)
PECO	$2,778,961	$4,695,559	($1,916,599)	$1,302,980,204	(0.1%)
PENELEC	$32,041,859	$38,701,452	($6,659,593)	$483,763,924	(1.4%)
Pepco	$71,117,429	$125,449,166	($54,331,737)	$1,079,848,058	(5.0%)
External	$1,802,461	$13,809,850	($12,007,389)	NA	NA
PPL	$4,093,757	$7,323,362	($3,229,605)	$1,290,220,318	(0.3%)
PSEG	$20,960,583	$81,776,784	($60,816,201)	$1,475,006,871	(4.1%)
RECO	($343,535)	$221,077	($564,612)	$47,469,825	(1.2%)
Total	$213,639,632	$411,771,002	($198,131,370)	$19,946,740,011	(1.0%)

Table 8-14 combines the results for the ARR related hedge and the FTR related hedge by zone. This is a measure of the total value of ARRs received by those who pay for the transmission system plus the total value of FTRs received by those who purchased FTRs in the FTR auctions. The combined ARR plus FTR credits hedges the largest percentage of total energy charges in the AP Control Zone (10.1 percent), and the lowest percentage of total energy charges in the Pepco Control Zone (-2.1 percent).

Table 8-14 ARRs and FTRs as a hedge against energy charges by control zone: January through September, 2009 (New Table)

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	$16,449,472	($13,349,187)	$3,100,285	$362,531,281	0.9%
AEP	$126,682,189	$45,101,500	$171,783,689	$3,430,853,351	5.0%
AP	$151,664,456	($11,038,985)	$140,625,471	$1,391,655,720	10.1%
BGE	$55,001,467	($17,221,055)	$37,780,411	$1,125,948,483	3.4%
ComEd	$33,062,400	$4,297,003	$37,359,403	$2,210,306,347	1.7%
DAY	$6,460,039	$2,927,288	$9,387,326	$441,017,205	2.1%
DLCO	$2,760,772	$6,438,240	$9,199,012	$352,284,804	2.6%
Dominion	$78,032,214	($19,945,840)	$58,086,374	$3,052,779,315	1.9%
DPL	$16,510,707	($12,063,284)	$4,447,423	$622,709,476	0.7%
JCPL	$37,956,077	($40,251,125)	($2,295,048)	$760,753,914	(0.3%)
Met-Ed	$7,819,134	($3,500,190)	$4,318,944	$483,838,555	0.9%
PECO	$13,294,503	($1,916,599)	$11,377,905	$1,302,980,204	0.9%
PENELEC	$35,865,428	($6,659,593)	$29,205,834	$483,763,924	6.0%
Pepco	$32,164,682	($54,331,737)	($22,167,055)	$1,079,848,058	(2.1%)
External	($816,126)	($12,007,389)	($12,823,515)	NA	NA
PPL	$10,150,211	($3,229,605)	$6,920,605	$1,290,220,318	0.5%
PSEG	$81,944,617	($60,816,201)	$21,128,416	$1,475,006,871	1.4%
RECO	($13,856)	($564,612)	($578,468)	$47,469,825	(1.2%)
Total	$704,988,384	($198,131,370)	$506,857,014	$19,946,740,011	2.5%

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