SECTION 2 – ENERGY MARKET, PART 1

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for January through September of 2011, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2011.

Table 2-1 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1200 with a minimum of 889 and a maximum of 1564 in the January through September period of 2011.

- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier test, used to test local market structure, indicate the existence of market power in a number of local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3]

Highlights

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

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

1 Analysis of 2011 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

2 OATT Attachment M

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Recommendations

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

Overview

Market Structure

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

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

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

- **Local Market Structure and Offer Capping.** PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first nine months of 2011. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours decreased from 0.2 percent in 2010 to 0.0 percent in the first nine months of 2011. In the Real-Time Energy Market offer-capped unit hours decreased from 1.2 percent in 2010 to 0.9 percent in the first nine months of 2011.

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

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

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

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

7 114 FERC ¶ 61,076.

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

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

Market Performance: Load, Generation and Locational Marginal Price

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

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

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

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

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

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

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

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

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

  PJM Real-Time Energy Market prices decreased in the first nine months of 2011 compared to the first nine months of 2010. The system simple

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

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

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

- **Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first nine months of 2011, 10.3 percent of real-time load was supplied by bilateral contracts, 26.4 percent by spot market purchases and 63.3 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased by 1.4 percentage points; reliance on spot supply increased by 6.2 percentage points; and reliance on self-supply decreased by 4.7 percentage points in 2011. In the first nine months of 2011, 5.6 percent of day-ahead load was supplied by bilateral contracts, 24.1 percent by spot market purchases and 70.3 percent by self-supply. Compared with 2010, reliance on bilateral contracts increased by 0.8 percentage points; reliance on spot supply increased by 4.8 percentage points; and reliance on self-supply decreased by 5.6 percentage points in 2011.

Demand-Side Response

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

  If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior.

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

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

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

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

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

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

Conclusion

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

Aggregate hourly supply offered increased by about 11,535 MWh in the third quarter of 2011 compared to the third quarter of 2010, while aggregate peak load increased by 21,556 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. In the Real-Time market, average load in the first nine months of 2011 increased from the same period in 2010, from 81,068 MW to 83,762 MW. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first nine months of 2011 generally reflected supply-demand fundamentals.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.[11]

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

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

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

Market Structure

Supply

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

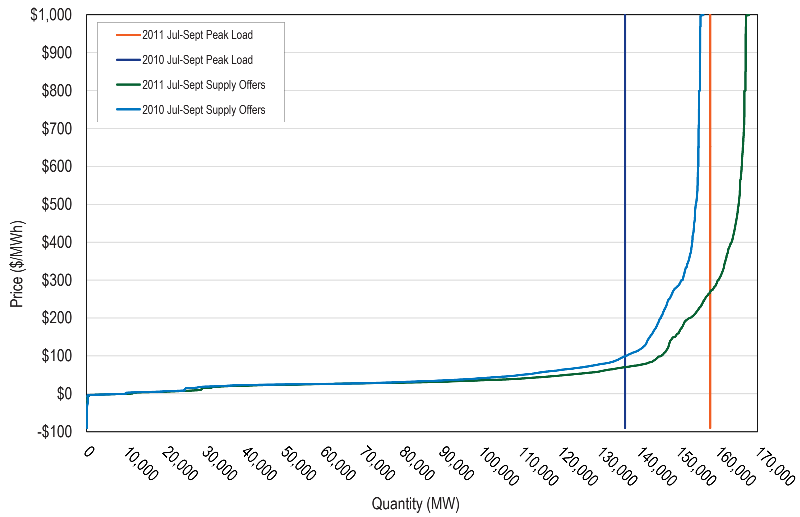


Table 2-2 Frequency distribution of day-ahead unit offer prices: July through September 2011 (See 2010 SOM, Table 2-3)

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

Demand

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

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2002	Wed, August 14	16	63,762	NA	NA
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Tue, August 03	17	77,887	16,387	26.6%
2005	Tue, July 26	16	133,761	55,875	71.7%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Thu, July 17	17	129,481	(9,947)	(7.1%)
2009	Mon, August 10	17	126,798	(2,683)	(2.1%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011 (with ATSI)	Thu, July 21	17	158,016	21,556	15.8%
2011 (without ATSI)	Thu, July 21	17	144,063	7,603	5.6%

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

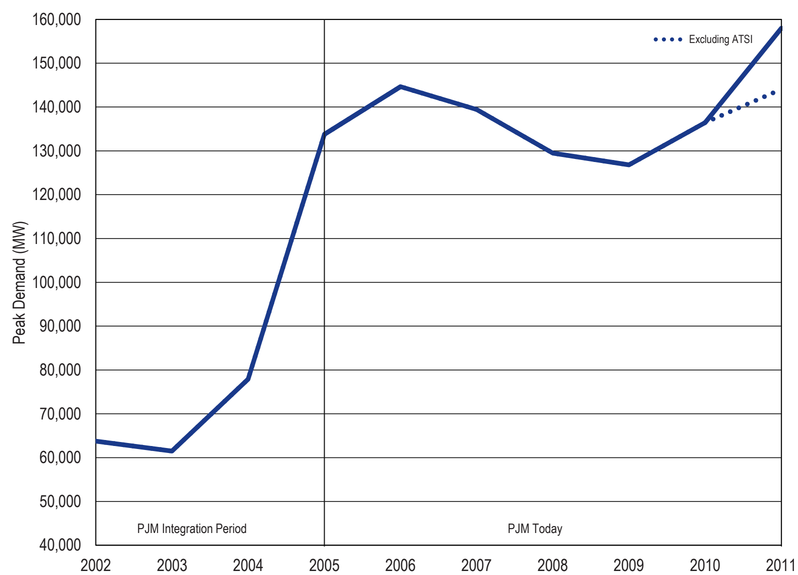
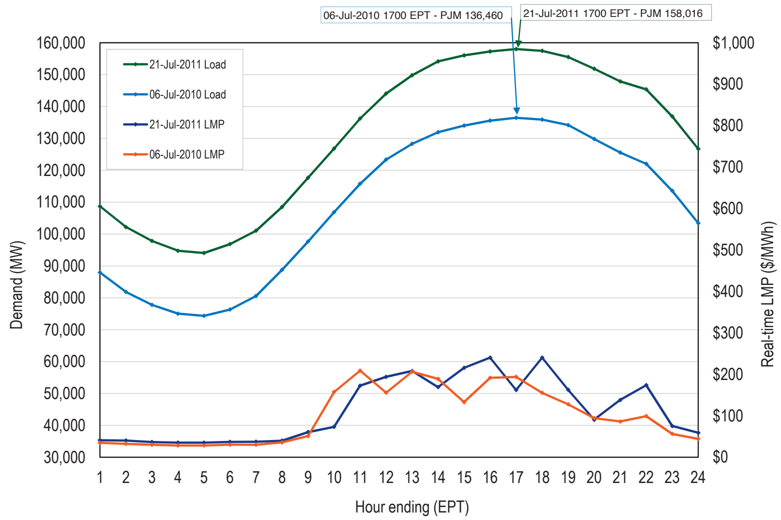


Figure 2-3 PJM third quarter peak-load comparison: Thursday, July 21, 2011, and Tuesday, July 06, 2010 (See 2010 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

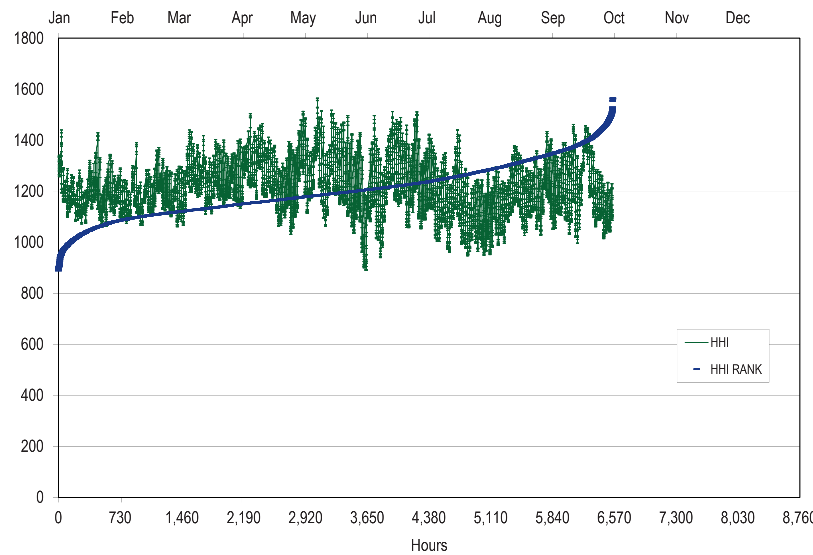
Table 2-4 PJM hourly Energy Market HHI: January through September 2011[12] (See 2010 SOM, Table 2-5)

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

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

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

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



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

Local Market Structure and Offer Capping

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

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011 (Jan - Sep)	0.9%	0.3%	0.0%	0.0%

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

	2011 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	4	9	5
80% and < 90%	0	0	1	1	4	9
75% and < 80%	0	0	0	0	3	3
70% and < 75%	0	0	0	0	2	6
60% and < 70%	0	1	0	1	1	23
50% and < 60%	0	0	0	1	10	24
25% and < 50%	1	0	0	3	14	77
10% and < 25%	5	1	1	1	1	51

Local Market Structure

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

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

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

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	316	373	15	2	13
	Off Peak	369	385	14	2	12
AEP-DOM	Peak	276	308	8	0	8
	Off Peak	350	423	8	0	8
AP South	Peak	392	449	8	0	8
	Off Peak	486	524	9	0	8
Bedington - Black Oak	Peak	70	75	8	0	8
	Off Peak	19	40	9	1	8
Dominion East	Peak	115	167	1	0	1
	Off Peak	80	148	2	0	2
East	Peak	637	898	16	5	11
	Off Peak	327	531	12	5	7
West	Peak	434	614	14	6	8
	Off Peak	218	423	13	5	8

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

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	6,653	396	6%	190	3%	48%
	Off Peak	3,657	182	5%	69	2%	38%
AEP-DOM	Peak	1,804	37	2%	14	1%	38%
	Off Peak	2,113	45	2%	24	1%	53%
AP South	Peak	16,791	206	1%	55	0%	27%
	Off Peak	12,230	208	2%	44	0%	21%
Bedington - Black Oak	Peak	41	0	0%	0	0%	0%
	Off Peak	9	0	0%	0	0%	0%
Dominion East	Peak	1,479	4	0%	0	0%	0%
	Off Peak	578	0	0%	0	0%	0%
East	Peak	726	12	2%	3	0%	25%
	Off Peak	155	1	1%	0	0%	0%
West	Peak	211	17	8%	7	3%	41%
	Off Peak	21	1	5%	0	0%	0%

Frequently Mitigated Unit and Associated Unit Adders

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

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

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

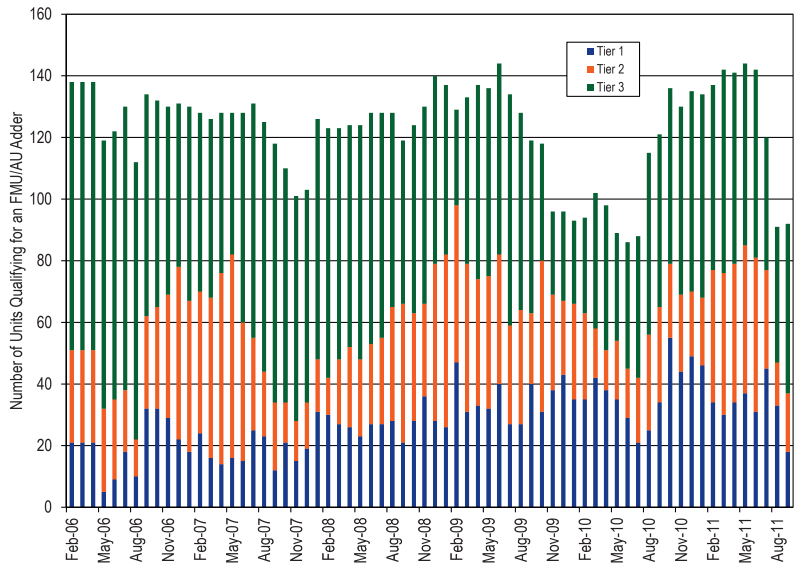


Figure 2-6 Frequently mitigated units and associated units total months eligible: February, 2006 through September, 2011 (New Figure)

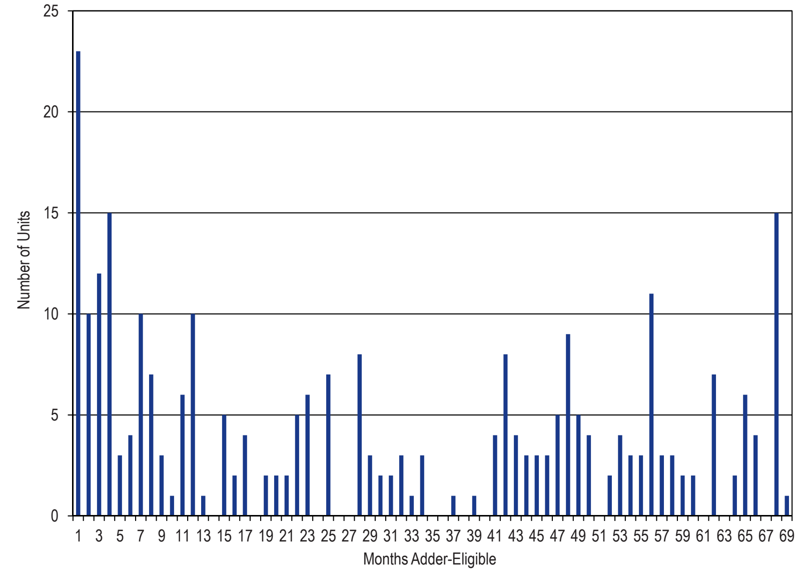


Table 2-12 Frequently mitigated units and associated units total months eligible: January through September 2011 (See 2010 SOM, Table 2-27)

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

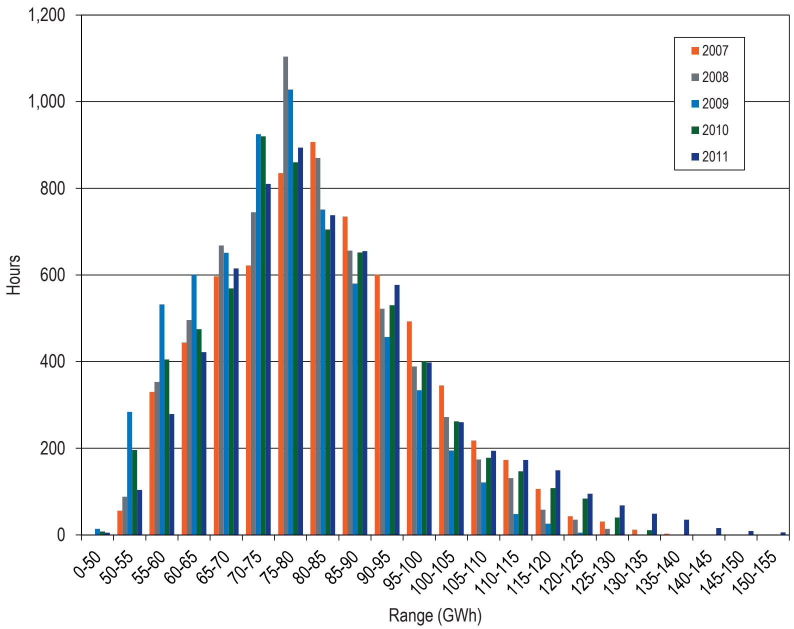
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

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



PJM Real-Time, Average Load

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

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

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

PJM Real-Time, Monthly Average Load

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

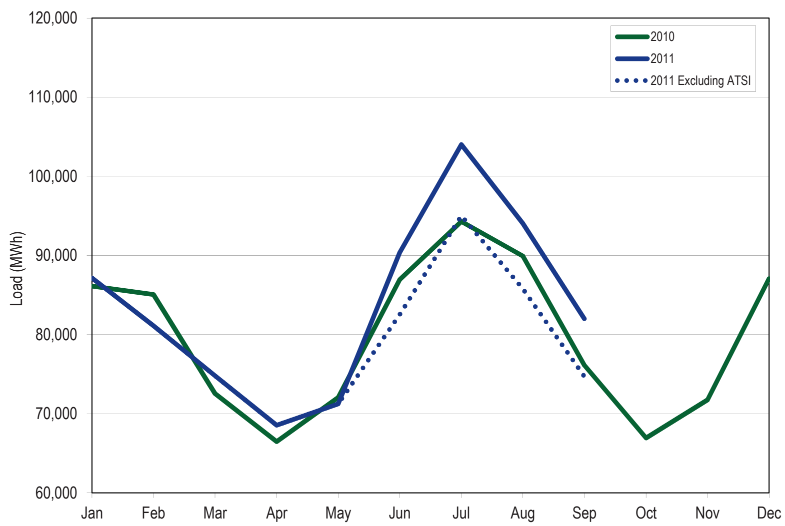


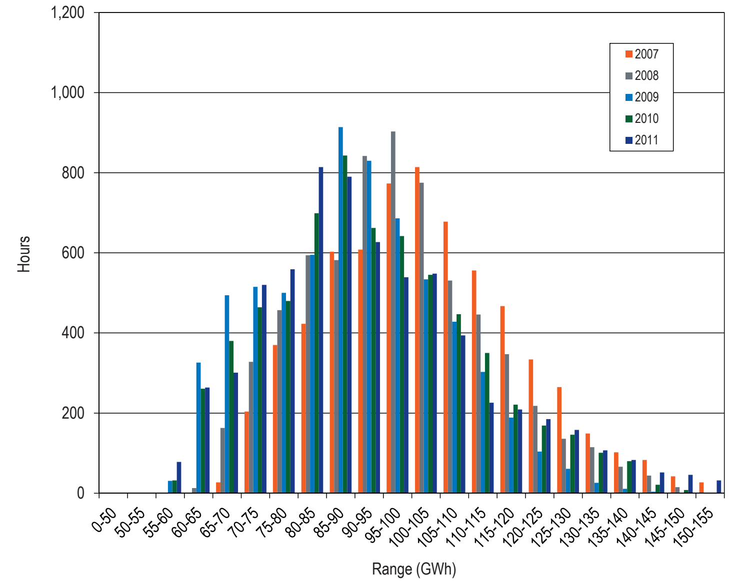
Table 2-14 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through September 2011 (See 2010 SOM, Table 2-30)

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

Day-Ahead Load

PJM Day-Ahead Load Duration

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



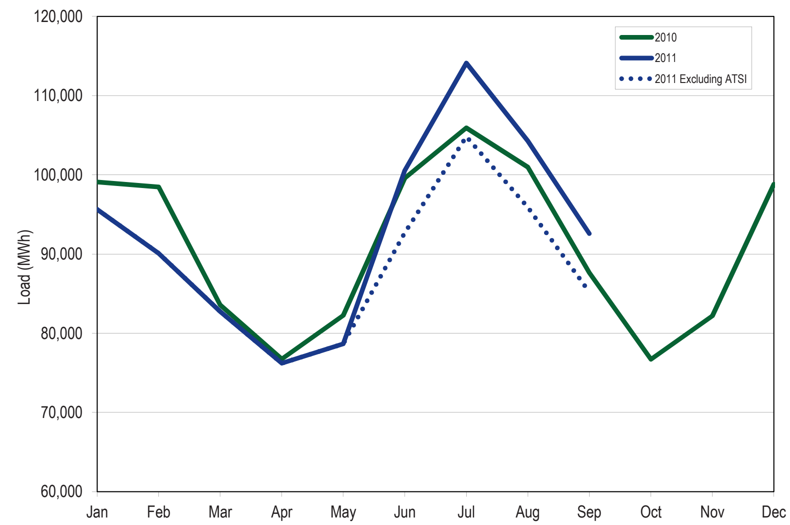
PJM Day-Ahead, Average Load

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

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

PJM Day-Ahead, Monthly Average Load

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



Real-Time and Day-Ahead Load

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

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

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

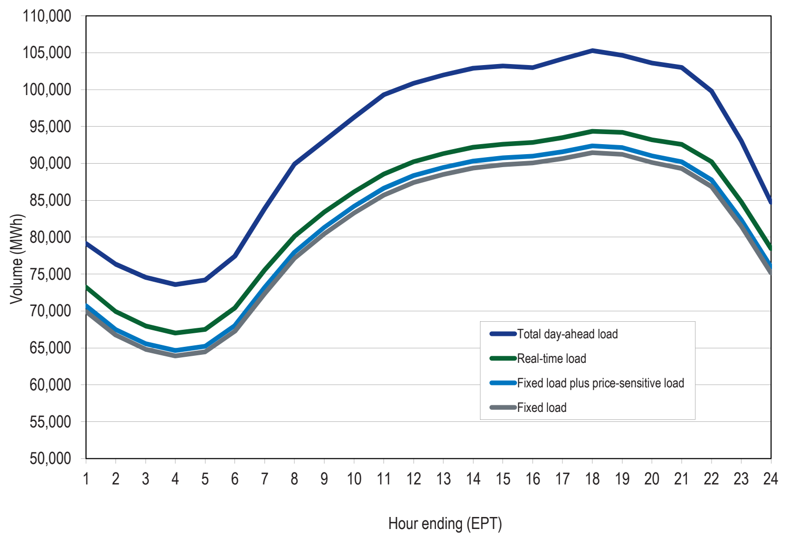
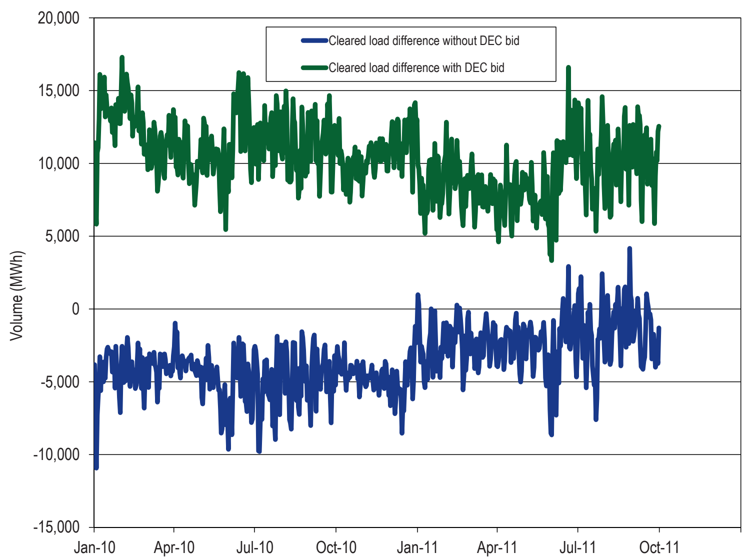


Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): January 2010 through September 2011 (See 2010 SOM, Figure 2-10)



Real-Time and Day-Ahead Generation

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

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

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

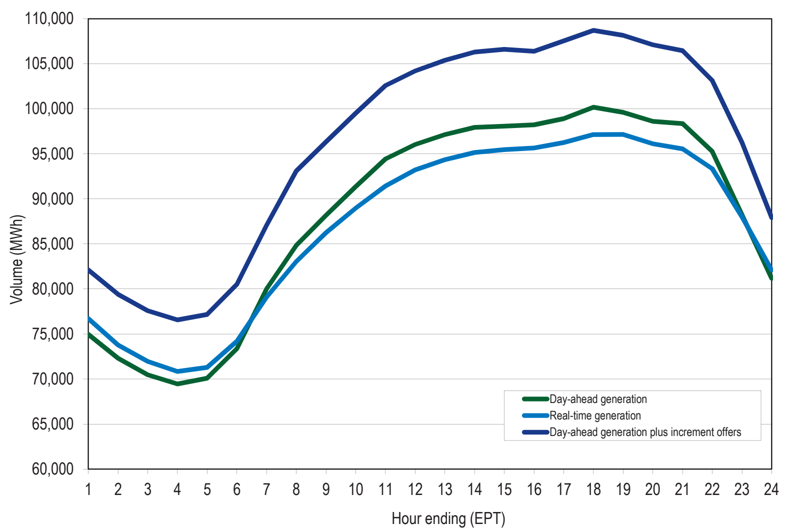
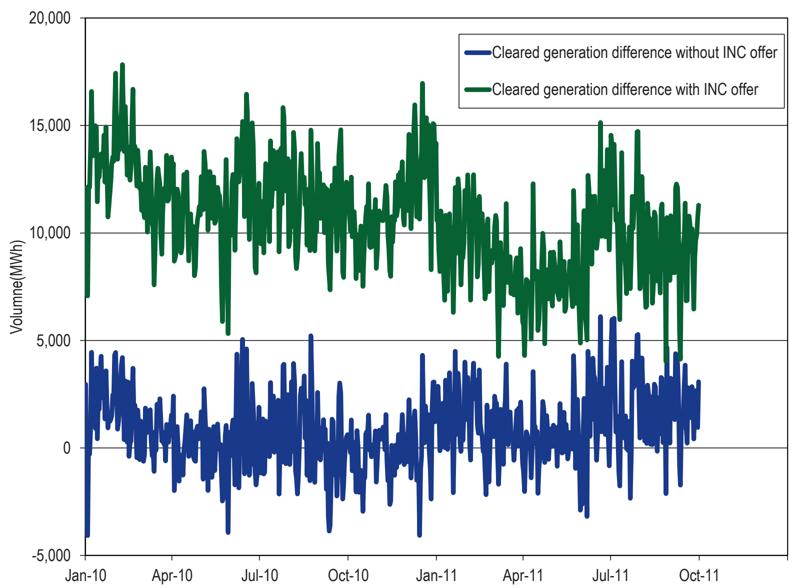


Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January 2010 through September 2011 (See 2010 SOM, Figure 2-12)



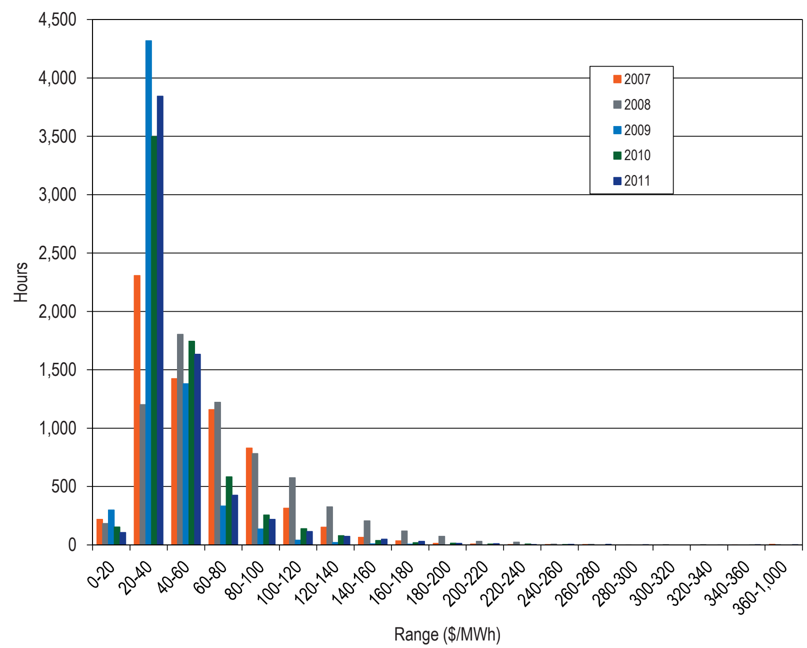
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

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



PJM Real-Time, Average LMP

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

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

Real-Time, Load-Weighted, Average LMP

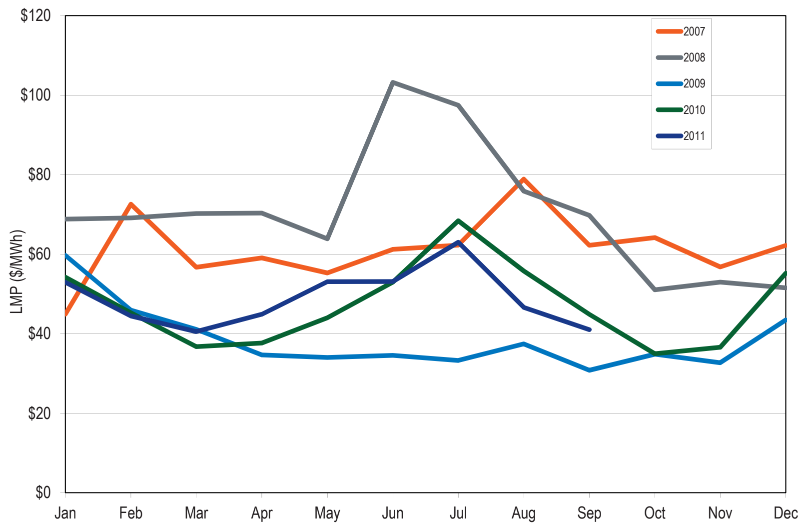
PJM Real-Time, Load-Weighted, Average LMP

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

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

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

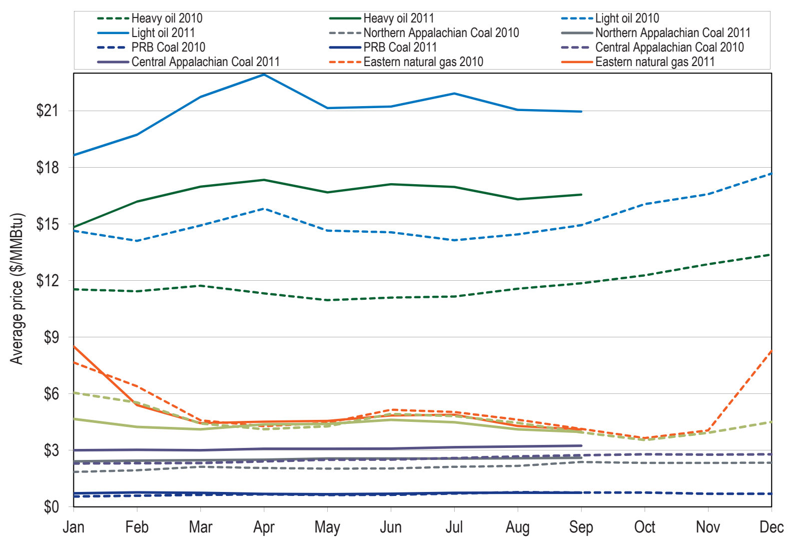
Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through September 2011 (See 2010 SOM, Figure 2-14)



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

Fuel Cost

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

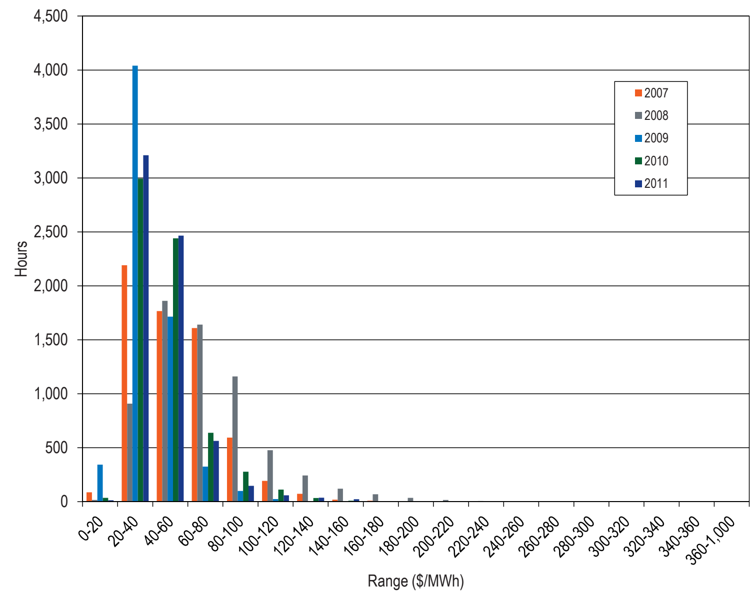


Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

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



PJM Day-Ahead, Average LMP

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

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

Day-Ahead, Load-Weighted, Average LMP

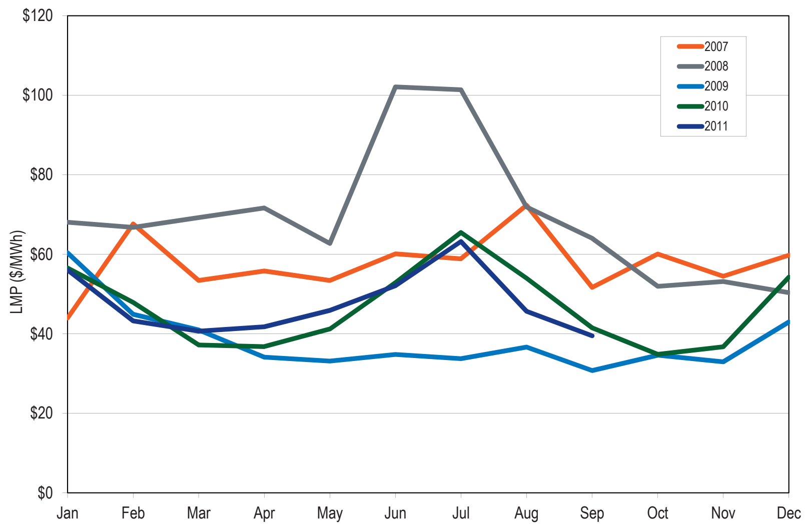
PJM Day-Ahead, Load-Weighted, Average LMP

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

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

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

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



Virtual Offers and Bids

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

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2010	Jan	11,144	21,634	282	936	17,513	29,406	266	893
2010	Feb	12,387	23,827	387	1,122	17,602	28,542	270	883
2010	Mar	10,811	21,062	308	915	15,019	24,968	253	763
2010	Apr	10,512	19,940	289	784	13,875	24,458	246	705
2010	May	11,165	19,744	218	806	15,556	25,194	223	787
2010	Jun	11,534	22,956	254	1,496	17,689	27,422	258	1,246
2010	Jul	11,276	23,414	250	1,585	17,223	25,690	304	1,284
2010	Aug	10,567	20,751	226	1,332	15,656	21,745	327	1,140
2010	Sep	10,944	21,365	263	1,232	15,522	22,646	311	1,072
2010	Oct	10,454	20,253	234	1,129	14,011	22,154	253	1,030
2010	Nov	11,134	17,495	220	1,035	15,315	22,618	271	1,055
2010	Dec	12,656	20,957	277	1,340	16,560	26,995	274	1,266
2010	Annual	11,208	21,101	267	1,143	15,952	25,135	271	1,011
2011	Jan	8,137	14,299	218	1,077	11,135	17,917	224	963
2011	Feb	8,532	16,263	215	1,672	11,076	17,355	230	1,034
2011	Mar	7,230	13,164	201	1,059	10,435	16,343	219	982
2011	Apr	7,222	12,516	185	984	10,211	16,199	202	846
2011	May	7,443	12,161	220	835	10,250	15,956	243	800
2011	Jun	8,405	14,171	238	1,084	11,648	17,542	279	1,015
2011	Jul	8,595	14,006	185	1,234	12,196	17,567	213	1,140
2011	Aug	7,540	12,349	120	1,034	10,992	15,368	161	847
2011	Sep	7,092	10,071	114	591	12,171	16,268	147	648
2011	Annual	7,794	13,199	188	1,059	11,122	16,718	213	919

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

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2010	Jan	5,647	9,549	114	189
2010	Feb	7,961	12,047	150	244
2010	Mar	8,796	12,916	149	234
2010	Apr	9,004	13,398	137	215
2010	May	7,430	12,114	131	208
2010	Jun	20,537	27,576	168	266
2010	Jul	30,176	40,006	202	336
2010	Aug	10,902	21,354	150	287
2010	Sep	10,114	21,777	156	488
2010	Oct	12,044	25,544	195	473
2010	Nov	14,380	29,788	261	602
2010	Dec	17,928	42,414	319	724
2010	Annual	12,910	22,374	178	355
2011	Jan	17,687	44,361	338	779
2011	Feb	17,759	48,052	386	877
2011	Mar	17,451	41,666	419	940
2011	Apr	16,114	38,182	488	1,106
2011	May	18,854	47,312	560	1,199
2011	Jun	18,323	45,802	508	1,141
2011	Jul	24,742	55,809	641	1,285
2011	Aug	28,996	60,531	654	1,348
2011	Sep	27,184	55,706	638	1,267
2011	Annual	20,790	48,602	515	1,105

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

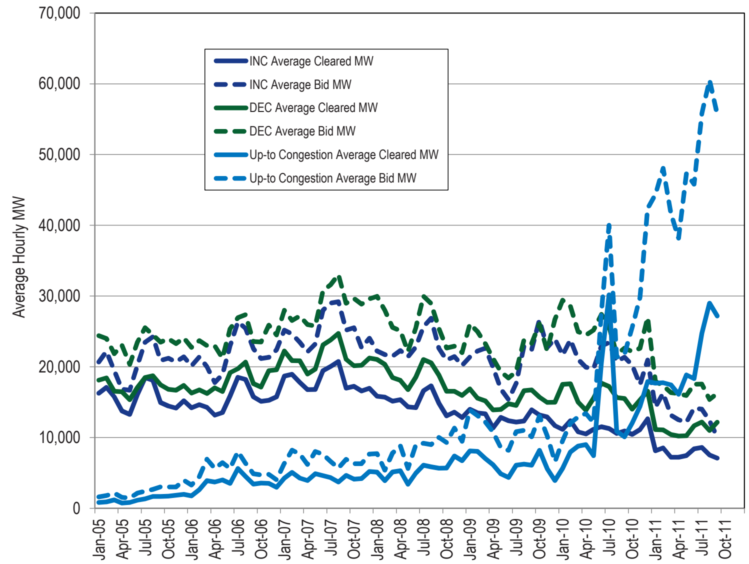


Table 2-24 PJM INC and DEC bids by type of parent organization (MW): January through September 2011 (See 2010 SOM, Table 2-63)

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

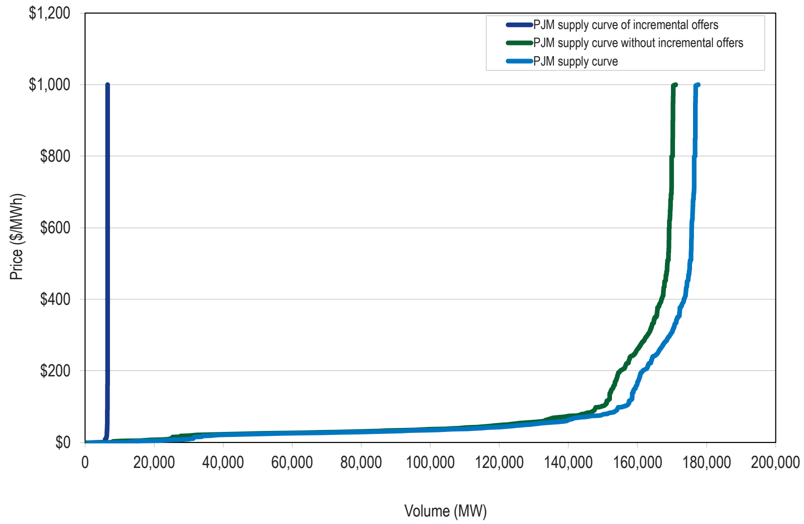
Table 2-25 PJM virtual offers and bids by top ten aggregates (MW): January through September 2010 and 2011 (See 2010 SOM, Table 2-64)

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

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

2010 (Jan-Sep)														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	COMED	ZONE	3,356,063	COMED	ZONE	MISO	INTERFACE	3,215,737	SOUTHIMP	INTERFACE	SOUTHEXP	INTERFACE	3,014,673
MISO	INTERFACE	DAY	ZONE	3,129,246	DAY	ZONE	MISO	INTERFACE	2,760,350	NCMPAIMP	INTERFACE	NCMPAEXP	INTERFACE	2,129,852
MISO	INTERFACE	COOK	EHVAGG	2,822,921	BEAV DUQ UNIT1	AGGREGATE	MICHFE	INTERFACE	2,034,993	NORTHWEST	INTERFACE	NIPSCO	INTERFACE	733,295
MISO	INTERFACE	AEP-DAYTON HUB	HUB	2,016,767	ROCKPORT	EHVAGG	MISO	INTERFACE	1,834,850	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	452,614
NYIS	INTERFACE	PSEG	ZONE	1,622,726	COOK	EHVAGG	MISO	INTERFACE	1,330,241	MISO	INTERFACE	OVEC	INTERFACE	203,546
MISO	INTERFACE	112 WILTON	EHVAGG	1,295,242	MT STORM	EHVAGG	MISO	INTERFACE	1,076,845	NORTHWEST	INTERFACE	MISO	INTERFACE	122,821
MISO	INTERFACE	GREENLAND GAP	EHVAGG	940,603	21 KINCA ATR24304	AGGREGATE	MISO	INTERFACE	816,791	OVEC	INTERFACE	MISO	INTERFACE	118,125
MISO	INTERFACE	ROCKPORT	EHVAGG	761,371	21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	565,514	NORTHWEST	INTERFACE	IMO	INTERFACE	116,579
NYIS	INTERFACE	MARION	AGGREGATE	634,715	WESTERN HUB	HUB	IMO	INTERFACE	534,406	SOUTHEAST	AGGREGATE	CPLEEXP	INTERFACE	113,000
MISO	INTERFACE	YUKON	EHVAGG	596,074	23 COLLINS	EHVAGG	MISO	INTERFACE	500,479	OVEC	INTERFACE	SOUTHEXP	INTERFACE	92,505
Top ten total				17,175,726					14,670,206					7,097,010
PJM total				55,024,722					49,156,193					9,210,022
Top ten total as percent of PJM total				31.2%					29.8%					77.1%
2011 (Jan-Sep)														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,697,394	LUMBERTON	AGGREGATE	SOUTHEAST	AGGREGATE	5,458,432	CPLEIMP	INTERFACE	NCMPAEXP	INTERFACE	397,775
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	1,950,476	WESTERN HUB	HUB	MISO	INTERFACE	2,629,676	CPLEIMP	INTERFACE	DUKEXP	INTERFACE	287,643
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	1,686,827	FE GEN	AGGREGATE	SOUTHWEST	AGGREGATE	1,286,402	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	204,835
MISO	INTERFACE	112 WILTON	EHVAGG	1,584,297	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,269,001	NORTHWEST	INTERFACE	MISO	INTERFACE	188,239
NYIS	INTERFACE	MARION	AGGREGATE	1,137,814	23 COLLINS	EHVAGG	MISO	INTERFACE	1,149,885	NYIS	INTERFACE	MICHFE	INTERFACE	115,574
NYIS	INTERFACE	PSEG	ZONE	966,283	21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	1,074,975	SOUTHWEST	AGGREGATE	OVEC	INTERFACE	111,932
SOUTHEAST	AGGREGATE	CRVWOOD	AGGREGATE	855,719	BELMONT	EHVAGG	OVEC	INTERFACE	934,962	MISO	INTERFACE	NIPSCO	INTERFACE	93,485
OVEC	INTERFACE	MARYSVILLE	EHVAGG	813,663	FOWLER 34.5 KV FWLR1AWF	AGGREGATE	OVEC	INTERFACE	783,782	NIPSCO	INTERFACE	OVEC	INTERFACE	71,840
OVEC	INTERFACE	JEFFERSON	EHVAGG	800,642	RECO	ZONE	IMO	INTERFACE	776,982	NIPSCO	INTERFACE	MISO	INTERFACE	63,809
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	798,145	BEAV DUQ UNIT1	AGGREGATE	MICHFE	INTERFACE	742,722	NCMPAIMP	INTERFACE	OVEC	INTERFACE	62,459
Top ten total				13,291,259					16,106,818					1,597,590
PJM total				75,607,294					58,031,610					2,813,116
Top ten total as percent of PJM total				17.6%					27.8%					56.8%

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



Price Convergence

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

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

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

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

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

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

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

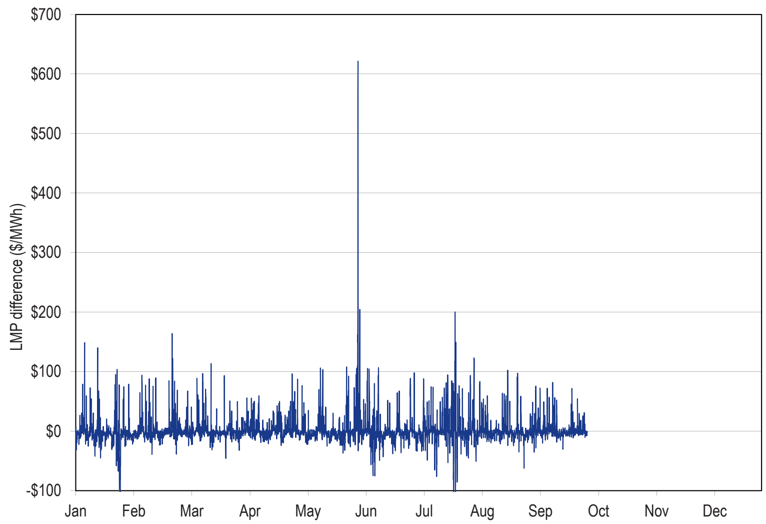


Figure 2-23 Monthly simple average of real-time minus day-ahead LMP: January through September 2011 (See 2010 SOM, Figure 2-20)

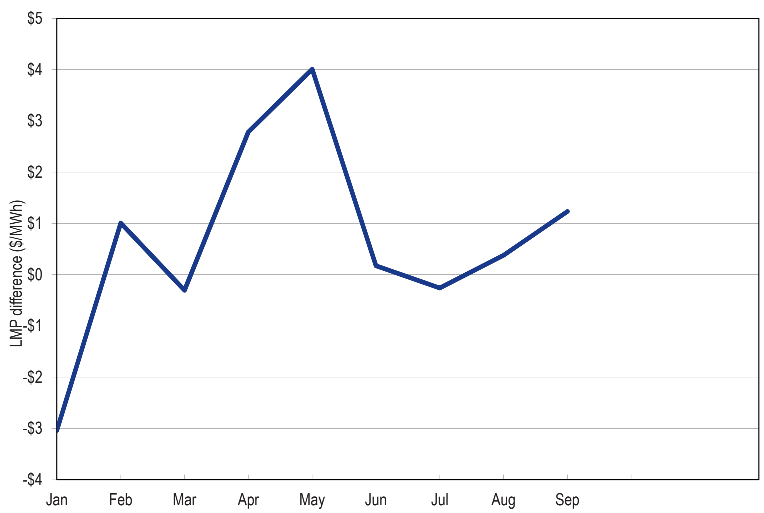
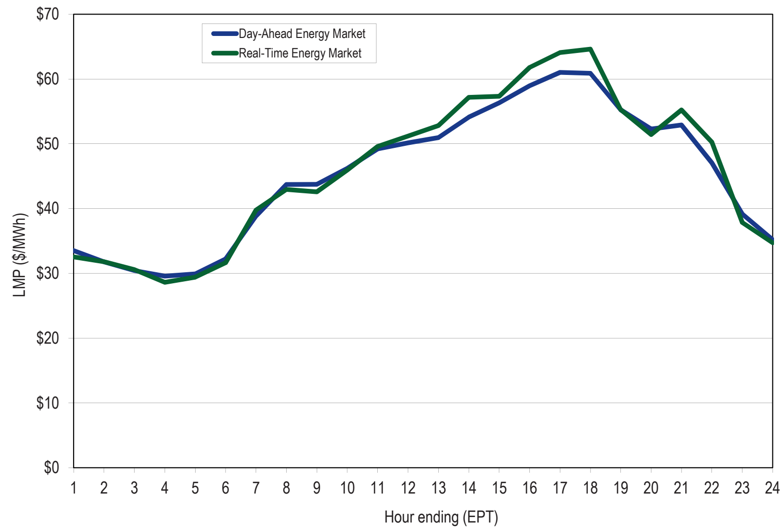


Figure 2-24 PJM system simple hourly average LMP: January through September 2011 (See 2010 SOM, Figure 2-21)



Load and Spot Market

Real-Time Load and Spot Market

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

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

Day-Ahead Load and Spot Market

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

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

Marginal Losses

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

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

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

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

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

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

Marginal Loss Costs and Loss Credits

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

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

Monthly Marginal Loss Costs

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

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

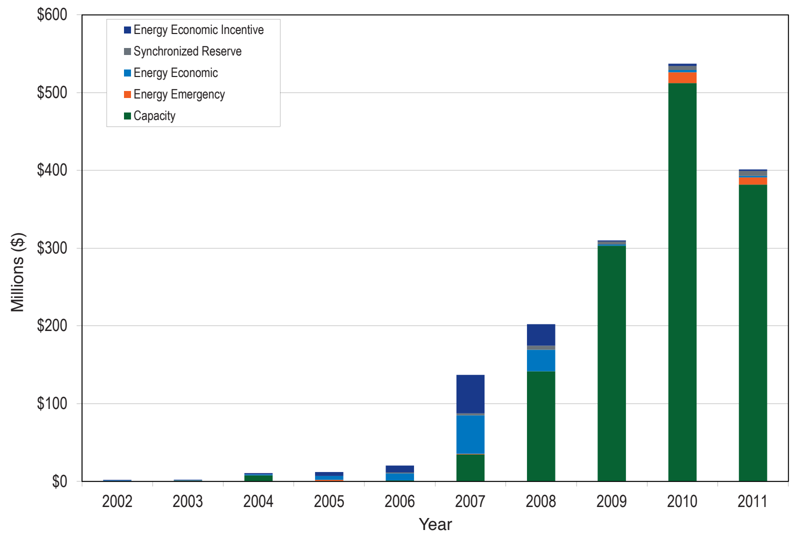
Demand-Side Response (DSR)

PJM Load Response Programs Overview

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

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

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



Economic Program

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

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
3-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
2-Aug-06	253	1,100.7
8-Aug-07	2,897	2,498.0
9-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
6-Jul-10	899	1,725.7
21-Jul-11	1,237	2,041.8

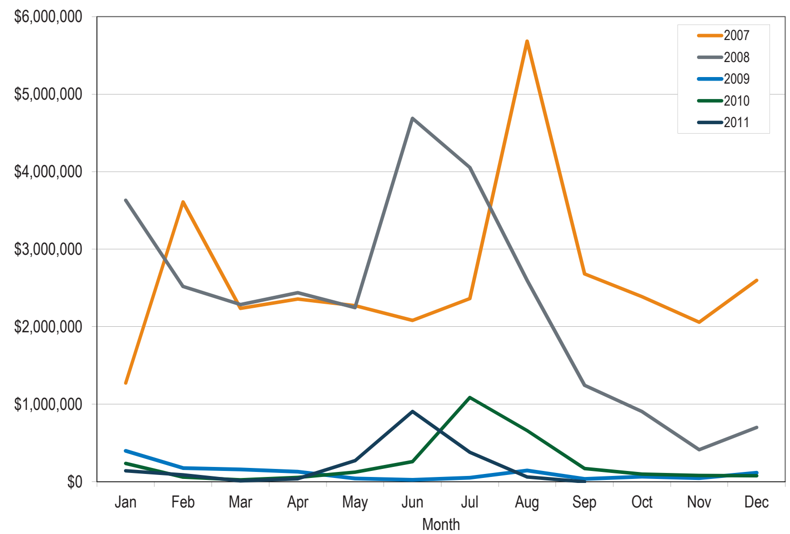
Table 2-38 Economic Program registrations on the last day of the month: January 2008 through September 2011 (See 2010 SOM, Table 2-74)

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

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

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

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



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

16 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 2-26 do not include these incentive payments.

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

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

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

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

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

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

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

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

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

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

Emergency Program

Load Management Program

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

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