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 March of 2011, 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 three 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 three months of 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1202 with a minimum of 1058 and a maximum of 1439 in January through March period of 2011.

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

- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.

- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs. In the first three months of 2011, the markup component of the PJM real-time, load-weighted, average LMP was $0.48 per MWh, or 1.0 percent.

- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

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

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. 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

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 948 MW, less than one percent, from 158,680 MW in the first three months of 2010 to 159,628 MW in the first three months of 2011.

- The PJM system peak load for the first three months of 2011 was 110,659 MW, which was 1,448 MW, or 1.3 percent, higher than the peak load in the first three months of 2010.

- PJM average real-time load in the first three months of 2011 decreased by 0.1 percent from the first three months of 2010, from 81,121 MW to 81,018 MW. PJM average day-ahead load in the first three months of 2011 decreased by 4.4 percent from the first three months of 2010, from 93,559 MW to 89,478 MW.

- PJM Real-Time Energy Market prices increased in the first three months of 2011 compared to the first three months of 2010. The load-weighted average LMP was 0.9 percent higher in the first three months of 2011 than in the first three months of 2010, $46.35 per MWh versus $45.92 per MWh.

- PJM Day-Ahead Energy Market prices decreased in the first three months of 2011 compared to the first three months of 2010. The load-weighted LMP was 1.3 percent lower in the first three months of 2011 than in the first three months of 2010, $47.14 per MWh versus $47.77 per MWh.

- Analysis of the real-time load-weighted LMP for the first three months of 2011 showed that 46.5 percent of the load-weighted LMP was the result of coal costs; 30.9 percent was the result of gas costs and 2.2 percent was the result of the cost of emission allowances. Markup was 1.0 percent of LMP, consistent with a competitive market outcome.

- Levels of offer capping for local market power remained low. In the first three months of 2011, 0.6 percent of unit hours and 0.2 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.

- In the first three months of 2011, the total MWh of load reduction under the Economic Program decreased by 5,900 MWh compared to the same period in 2010, from 8,100 MWh in 2010 to 2,100 MWh in 2011, a 74 percent decrease. Total payments under the Economic Program decreased by $176,000, from $321,600 in 2010 to $145,600 in 2010, a 55 percent decrease.

- In the first three months of 2011, total capacity payments under the Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, increased by $43 million, or 43 percent, compared to the same period in 2010, from $101 Million in 2010 to $144 Million in 2011.

Summary Recommendations

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

Overview

Market Structure

- **Supply.** During the first three months of 2011, the PJM Energy Market received an hourly average of 159,628 MWh in day-ahead supply offers including hydroelectric generation, 948 MWh higher than the first three months of 2010 average daily offered supply of 158,680 MWh.[4]

- **Demand.** The PJM system peak load for the first three months of 2011 was 110,659 MW in the hour ended 800 EPT on January 24, 2011, which was 1,448 MW, or 1.3 percent, higher than the PJM peak load

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.

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

for the first three months of 2010, which was 109,210 MW in the hour ended 1900 EPT on January 4, 2010.[5]

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

- **Local Market Structure and Offer Capping.** A noncompetitive local market structure is the trigger for offer capping. PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first three 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 three months of 2011. In the Real-Time Energy Market offer-capped unit hours decreased from 1.2 percent in 2010 to 0.6 percent in the first three months of 2011.

- **Local Market Structure.** In the first three months of 2011, the AECO, AEP, AP, ComEd, Dominion, DPL, PECO, PENELEC, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.[6]

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

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

Market Performance: 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 in the first three months of 2011 was $0.48 per MWh, or 1.0 percent. Coal steam units contributed $0.24 to the total markup component of LMP. Combustion turbine units that use natural gas as their primary fuel source contributed $0.05 to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.20 to the total markup component of LMP. During the same period, the markup was $1.28 per MWh during peak hours and -$0.38 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP for the first three months of 2011 was -$0.98 per MWh, or -2.1 percent. Coal steam units contributed -$0.77 to the total markup component of LMP. Natural gas steam units contributed -$0.21 to the total markup component of LMP. The markup was -$0.46 per MWh during peak hours and -$1.51 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 three months of 2011 by 0.1 percent from the first three months of 2010, from 81,121 MW to 81,018 MW. PJM day-ahead load decreased in the first three months of 2011 by 4.4 percent from the first three months of 2010, from 93,559 MW to 89,478 MW.

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

  PJM Real-Time Energy Market prices increased in the first three months of 2011 compared to the first three months of 2010. The system simple average LMP was 1.4 percent higher in the first three months of 2011 than in the first three months of 2010, $44.76 per MWh versus $44.13 per MWh. The load-weighted LMP was 0.9 percent higher in the first three months of 2011 than in the first three months of 2010, $46.35 per MWh versus $45.92 per MWh.

  The real-time, fuel cost adjusted, load-weighted, average LMP was 7.0 percent lower in the first three months of 2011 than the real-time, load weighted LMP in the first three months of 2010 , $42.73 per MWh versus $45.92 per MWh.[7] In other words, if fuel costs in the first three months of 2011 had been the same as they were in the first three months of 2010, the load-weighted LMP of the first three months of 2011 would have been 7.8 percent lower, $42.73 per MWh, than the actual $46.35 per MWh, and 7.0 percent lower than the load-weighted average LMP for the first three months of 2010. Higher cost of coal and oil contributed to upward pressure on LMP in the first three months of 2011 compared to the first three months of 2010.

  PJM Day-Ahead Energy Market prices decreased in the first three months of 2011 compared to the first three months of 2010. The system simple average LMP was 1.2 percent lower in the first three months of 2011 than in the first three months of 2010, $45.60 per MWh versus $46.13 per MWh. The load-weighted LMP was 1.3 percent lower in the first three months of 2011 than in the first three months of 2010, $47.14 per MWh versus $47.77 per MWh.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first three months of 2011, 10.1 percent of real-time load was supplied by bilateral contracts, 28.7 percent by spot market purchases and 61.2 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased by 1.7 percentage points; reliance on spot supply increased by 8.4 percentage points; and reliance on self-supply decreased by 6.8 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 three months of 2011, in the Economic Program, participation decreased compared to the same period in 2010. Settled MWh and credits were lower in 2011 compared to 2010, and there were generally fewer settlements submitted, fewer registered customers, and fewer active customers compared to the same period in 2010. Participation levels since calendar year 2008 have generally been lower compared to prior years due to a number

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

of factors, including lower price levels, lower load levels and improved measurement and verification. In 2010, participation showed strong growth through the summer period as price levels and load levels increased. Through the first three months of 2011, there were relatively few high load days and limited hours of sufficiently high LMPs for economic load reduction. On the peak load day for the period January through March 2011 (January 24, 2011), there were 2,445.2 MW registered in the Economic Load Response Program.

That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are assessed compliance on a zonal basis, is a broader issue that needs to be addressed. More precise locational deployment of Load Management improves efficiency while reducing the ability of a CSP to aggregate customers. The Demand Response Subzonal Dispatch Task Force (DRSDTF) was established at the Markets Reliability Committee (MRC) on February 16, 2011 in response to stakeholders' request for clarity on potential future subzonal event deployments and the implications for event performance calculations. The DRSDTF was dissolved at the April 27, 2011, MRC meeting, and its responsibilities were transferred to the newly established Demand Response Subcommittee (DRS).

Since the implementation of the RPM design on June 1, 2007, capacity revenue has become the primary source of revenue to participants in PJM demand side programs. In the first three months of 2011, Economic Program revenues decreased by $176,000 or 55 percent compared to the same period in 2010, from $321,600 to $145,600 while Load Management (LM) Program revenues increased by $43 million or 43 percent, from $101 million to $144 million. Through the first three months of 2011, Synchronized Reserve credits increased by $1.1 million compared to the same period in 2010, from $1.2 million in 2010 to $2.3 million in 2011. In the first three months of 2010 and 2011, since there were no Load Management Events, there were no emergency energy revenues.

Conclusion

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

Aggregate hourly supply offered increased by about 948 MWh in the first three months of 2011 compared to the first three months of 2010, while aggregate peak load increased by 1,448 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. Average load in the first three months of 2011 decreased from the same period in 2010, falling from 81,121 MW to 81,018 MW. Market concentration levels remained moderate and average markup was slightly positive. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, 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 three months of 2011 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher fuel costs.

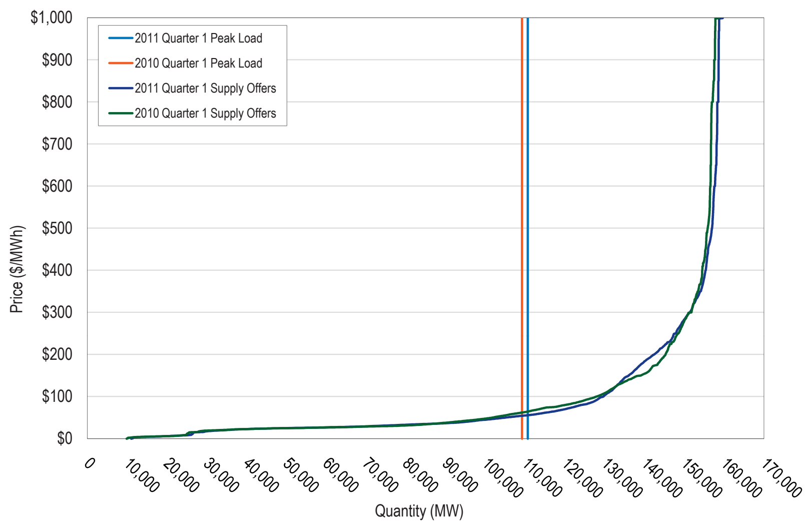
The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required 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.[8]

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 three months of 2011.

Market Structure

Supply

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



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.

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

Range	All Offers	Pool-Scheduled Share of All Offers	Self-Scheduled Share of All Offers
($200) - $0	9.5%	21.2%	78.8%
$0 - $200	60.8%	88.6%	11.4%
$200 - $400	19.8%	98.7%	1.3%
$400 - $600	5.2%	98.2%	1.8%
$600 - $800	1.1%	91.1%	8.9%
$800 - $1,000	3.6%	92.1%	7.9%

Demand

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

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2003	Thu, January 23	19	54,670	NA	NA
2004	Mon, January 26	19	53,620	(1,050)	(1.9%)
2005	Tue, January 18	19	96,362	42,742	79.7%
2006	Mon, February 13	20	100,065	3,703	3.8%
2007	Mon, February 05	20	118,800	18,736	18.7%
2008	Thu, January 03	19	111,724	(7,076)	(6.0%)
2009	Fri, January 16	19	117,169	5,445	4.9%
2010	Mon, January 04	19	109,210	(7,959)	(6.8%)
2011	Mon, January 24	8	110,659	1,448	1.3%

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

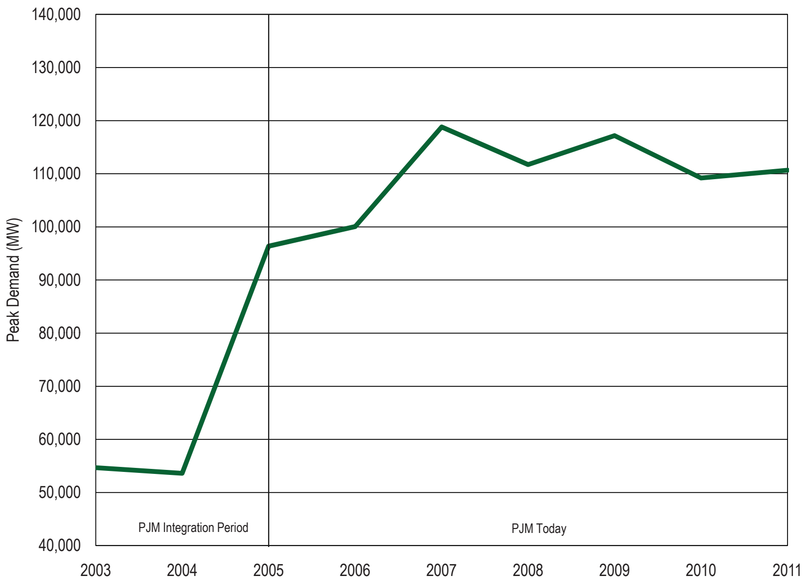
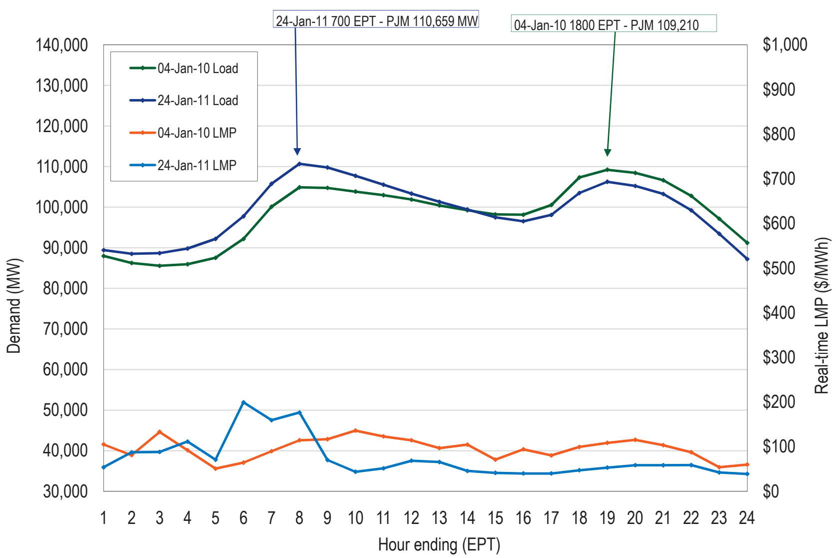


Figure 2-3 PJM first quarter peak-load comparison: Monday, January 24, 2011, and Monday, January 4, 2010 (See 2010 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

Table 2-4 PJM hourly Energy Market HHI: January through March 2011[9] (See 2010 SOM, Table 2-5)

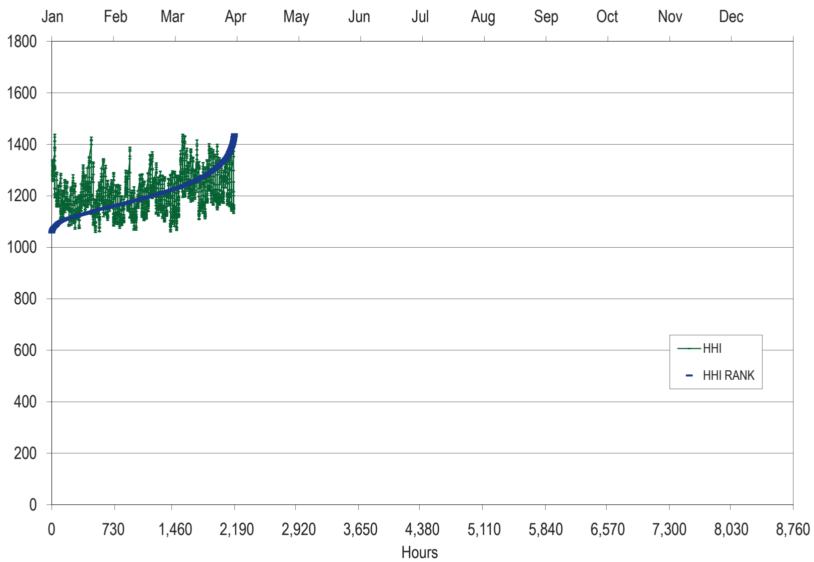
	Hourly Market HHI
Average	1202
Minimum	1058
Maximum	1439
Highest market share (One hour)	28%
Highest market share (All hours)	21%
# Hours	2,159
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

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

	Minimum	Average	Maximum
Base	1079	1224	1441
Intermediate	933	2162	6885
Peak	1084	7002	10000

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

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



Local Market Structure and Offer Capping

Table 2-6 Annual offer-capping statistics: Calendar years 2007 through March 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	0.6%	0.2%	0.0%	0.0%

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

	2011 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	0	48
80% and < 90%	0	0	0	0	1	14
75% and < 80%	0	0	0	0	0	5
70% and < 75%	0	0	0	0	0	4
60% and < 70%	0	0	0	0	0	25
50% and < 60%	0	0	0	0	0	17
25% and < 50%	0	0	1	0	0	26
10% and < 25%	0	0	0	1	0	5

Local Market Structure

Table 2-8 Three pivotal supplier results summary for regional constraints: January through March 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	3,940	762	19%	3,659	93%
	Off Peak	1,989	236	12%	1,888	95%
AEP-DOM	Peak	582	4	1%	582	100%
	Off Peak	1,913	32	2%	1,904	100%
AP South	Peak	11,516	180	2%	11,451	99%
	Off Peak	7,936	163	2%	7,878	99%
Dominion East	Peak	240	12	5%	230	96%
	Off Peak	92	8	9%	89	97%
East	Peak	726	221	30%	636	88%
	Off Peak	155	63	41%	118	76%
West	Peak	146	87	60%	96	66%
	Off Peak	15	5	33%	14	93%

Table 2-9 Three pivotal supplier test details for regional constraints: January through March 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	288	1,858	14	2	12
	Off Peak	314	1,962	14	1	12
AEP-DOM	Peak	358	931	8	0	8
	Off Peak	367	1,297	8	0	8
AP South	Peak	393	1,044	7	0	7
	Off Peak	449	1,193	8	0	8
Dominion East	Peak	42	231	2	1	2
	Off Peak	38	391	4	1	3
East	Peak	637	4,408	16	5	11
	Off Peak	327	3,323	12	5	7
West	Peak	445	3,622	15	8	7
	Off Peak	251	3,260	13	3	10

Table 2-10 Summary of three pivotal supplier tests applied to uncommitted units for regional constraints: January through March 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	3,940	117	3%	43	1%	37%
	Off Peak	1,989	81	4%	24	1%	30%
AEP-DOM	Peak	582	16	3%	10	2%	63%
	Off Peak	1,913	39	2%	24	1%	62%
AP South	Peak	11,516	87	1%	16	0%	18%
	Off Peak	7,936	164	2%	31	0%	19%
Dominion East	Peak	240	3	1%	0	0%	0%
	Off Peak	92	0	0%	0	0%	0%
East	Peak	726	12	2%	3	0%	25%
	Off Peak	155	1	1%	0	0%	0%
West	Peak	146	3	2%	0	0%	0%
	Off Peak	15	0	0%	0	0%	0%

Ownership of Marginal Resources

Table 2-11 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through March 2011 (See 2010 SOM, Table 2-12)

Company	Percent of Price
1	20%
2	12%
3	12%
4	11%
5	5%
6	5%
7	5%
8	3%
9	3%
Other (54 companies)	24%

Table 2-12 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through March 2011 (See 2010 SOM, Table 2-13)

Company	Percent of Price
1	11%
2	9%
3	7%
4	6%
5	6%
6	5%
7	4%
8	4%
9	4%
Other (101 companies)	44%

Fuel Type of Marginal Units

Table 2-13 Type of fuel used (By real-time marginal units): January through March 2011 (See 2010 SOM, Table 2-14)

Fuel Type	2011
Coal	74%
Gas	23%
Wind	2%

Table 2-14 Day-ahead marginal resources by type/fuel: January through March 2011 (See 2010 SOM, Table 2-15)

Type/Fuel	2011
Transaction	67%
DEC	14%
INC	9%
Coal	8%
Natural gas	2%
Price sensitive demand	0%
Oil	0%
Municipal waste	0%

Market Conduct: Markup

Real-Time Mark Up Conduct

Table 2-15 Average, real-time marginal unit markup index (By price category): January through March 2011 (See 2010 SOM, Table 2-16)

Price Category	Average Markup Index	Average Dollar Markup
Below $25	(0.14)	($3.10)
$25 to $50	(0.02)	($1.36)
$50 to $75	(0.00)	($0.51)
$75 to $100	0.05	$3.58
$100 to $125	0.22	$23.22
$125 to $150	0.15	$18.64
Above $150	0.11	$24.48

Day-Ahead Mark Up Conduct

Table 2-16 Average marginal unit markup index (By price category): January through March 2011 (See 2010 SOM, Table 2-17)

Price Category	Average Markup Index	Average Dollar Markup
Below $25	(0.13)	($3.84)
$25 to $50	(0.03)	($1.58)
$50 to $75	0.00	$0.20
$75 to $100	0.02	$1.77
$100 to $125	0.02	$2.16
$125 to $150	0.00	$0.00
Above $150	0.15	$28.20

Market Performance

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

Table 2-17 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through March 2011 (See 2010 SOM, Table 2-18)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	$0.24	51.3%
Gas	CC	$0.20	41.1%
Gas	CT	$0.05	9.5%
Gas	Diesel	($0.00)	(0.1%)
Gas	Steam	$0.01	1.6%
Interface	Interface	$0.00	0.0%
Municipal Waste	Steam	($0.00)	(0.8%)
Oil	CT	$0.00	0.7%
Oil	Diesel	($0.00)	(0.0%)
Oil	Steam	($0.02)	(4.7%)
Wind	Wind	$0.01	1.3%
Total		$0.48	100.0%

Markup Component of Real-Time System Price

Table 2-18 Monthly markup components of real-time load-weighted LMP: January through March 20110 (See 2010 SOM, Table 2-19)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.10	$1.77	$0.47
Feb	($0.16)	$0.23	($0.57)
Mar	$0.37	$1.73	($1.19)
2011	$0.48	$1.28	($0.38)

Markup Component of Real-Time Zonal Prices

Table 2-19 Average real-time zonal markup component: January through March 2011 (See 2010 SOM, Table 2-20)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$0.80	$1.91	($0.37)
AEP	($0.34)	$0.33	($1.03)
AP	($0.18)	$0.41	($0.83)
BGE	$1.21	$2.08	$0.28
ComEd	$0.46	$0.73	$0.19
DAY	($0.40)	$0.38	($1.25)
DLCO	($0.71)	($0.01)	($1.46)
Dominion	$1.31	$1.93	$0.63
DPL	$0.82	$1.87	($0.27)
JCPL	$0.85	$2.33	($0.76)
Met-Ed	$0.76	$1.83	($0.41)
PECO	$0.85	$2.02	($0.41)
PENELEC	($0.04)	$0.66	($0.83)
Pepco	$1.32	$2.08	$0.44
PPL	$0.80	$2.01	($0.53)
PSEG	$0.66	$2.40	($1.27)
RECO	$1.42	$1.57	$1.22

Markup by Real-Time System Price Levels

Table 2-20 Average real-time markup component (By price category): January through March 2011 (See 2010 SOM, Table 2-21)

	Average Markup Component	Frequency
Below $20	($4.28)	0.5%
$20 to $40	($2.10)	58.7%
$40 to $60	($0.38)	28.6%
$60 to $80	$7.55	5.6%
$80 to $100	$15.39	2.4%
$100 to $120	$18.17	1.7%
$120 to $140	$15.94	1.2%
$140 to $160	$15.99	0.7%
Above $160	$25.01	0.7%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

Table 2-21 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through March 2011 (See 2010 SOM, Table 2-22)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.77)	79.1%
Municipal waste	Steam	($0.00)	0.1%
Natural gas	CT	$0.01	(0.9%)
Natural gas	Diesel	$0.00	0.0%
Natural gas	Steam	($0.21)	21.1%
Oil	Steam	($0.01)	0.5%
Total		($0.98)	100.0%

Markup Component of Day-Ahead System Price

Table 2-22 Monthly markup components of day-ahead, load-weighted LMP: January through March 2011 (See 2010 SOM, Table 2-23)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.48)	$0.13	($1.04)
Feb	($1.36)	($1.14)	($1.59)
Mar	($1.18)	($0.44)	($2.04)
Annual	($0.98)	($0.46)	($1.51)

Markup Component of Day-Ahead Zonal Prices

Table 2-23 Day-ahead, average, zonal markup component: January through March 2011 (See 2010 SOM, Table 2-24)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.83)	($0.21)	($1.49)
AEP	($1.23)	($0.67)	($1.81)
AP	($1.15)	($0.47)	($1.87)
BGE	($1.04)	($0.40)	($1.69)
ComEd	($0.59)	($0.44)	($0.75)
DAY	($1.16)	($0.67)	($1.68)
DLCO	($1.23)	($0.79)	($1.70)
Dominion	($1.09)	($0.45)	($1.72)
DPL	($0.82)	($0.18)	($1.45)
JCPL	($0.98)	($0.47)	($1.55)
Met-Ed	($0.99)	($0.48)	($1.53)
PECO	($0.74)	($0.11)	($1.40)
PENELEC	($0.98)	($0.48)	($1.56)
Pepco	($1.04)	($0.43)	($1.70)
PPL	($0.94)	($0.52)	($1.39)
PSEG	($0.75)	($0.24)	($1.33)
RECO	($0.66)	($0.20)	($1.21)

Markup by Day-Ahead System Price Levels

Table 2-24 Average, day-ahead markup (By price category): January through March 2011 (See 2010 SOM, Table 2-25)

	Average Markup Component	Frequency
Below $20	$0.00	0%
$20 to $40	($2.25)	50%
$40 to $60	($0.47)	39%
$60 to $80	($0.82)	5%
$80 to $100	($0.01)	3%
$100 to $120	$2.62	1%
$120 to $140	($1.10)	0%
$140 to $160	($1.07)	0%
Above $160	($1.97)	0%

Frequently Mitigated Unit and Associated Unit Adders

Table 2-25 Frequently mitigated units and associated units (By month): January through March 2011 (See 2010 SOM, Table 2-26)

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
Jan	46	22	66	134
Feb	34	43	60	137
Mar	30	46	66	142

Table 2-26 Frequently mitigated units and associated units total months eligible: January through March 2011 (See 2010 SOM, Table 2-27)

Months Adder-Eligible	FMU & AU Count
Jan	4
Feb	14
Mar	127
Total	145

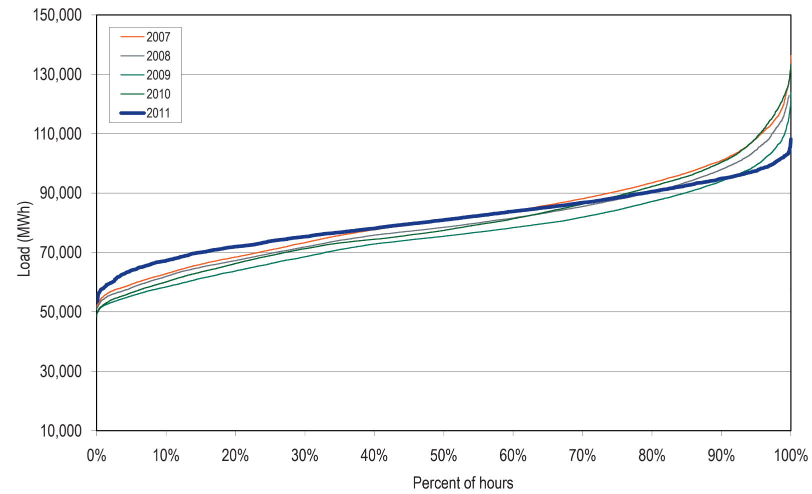
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

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



PJM Real-Time, Annual Average Load

Table 2-27 PJM real-time average hourly load: Calendar years 1998 through March 2011 (See 2010 SOM, Table 2-28)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	76,035	75,471	13,260	(4.4%)	(3.8%)	(3.6%)
2010	79,611	77,430	15,504	4.7%	2.6%	16.9%
2011	81,018	80,991	10,273	1.8%	4.6%	(33.7%)

PJM Real-Time, Monthly Average Load

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

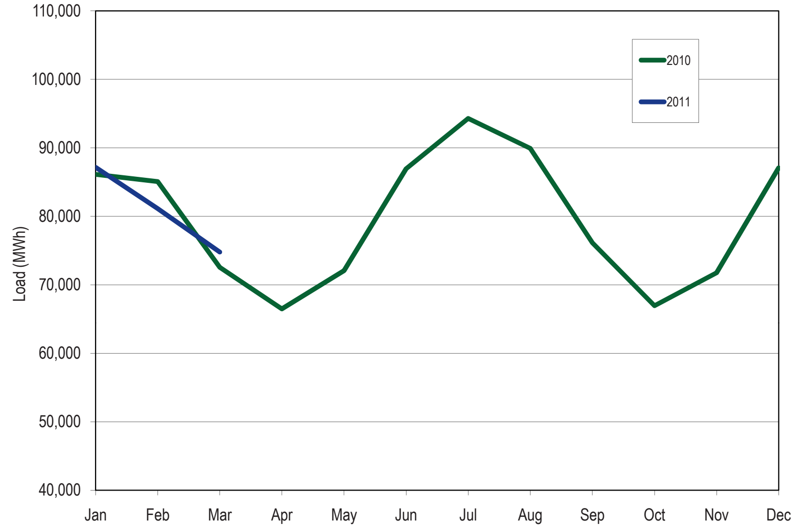


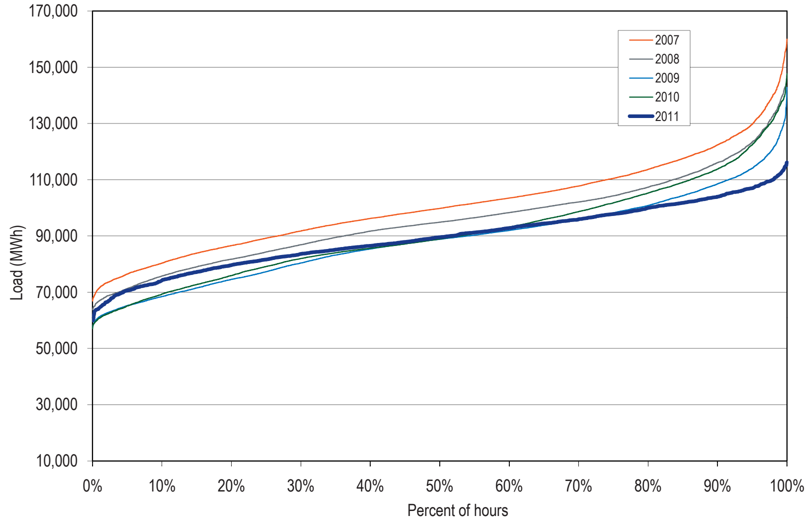
Table 2-28 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through March 2011 (See 2010 SOM, Table 2-30)

	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	NA	25.20	42.26

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-7 PJM day-ahead load duration curves: Calendar years 2007 through March 2011 (See 2010 SOM, Figure 2-7)



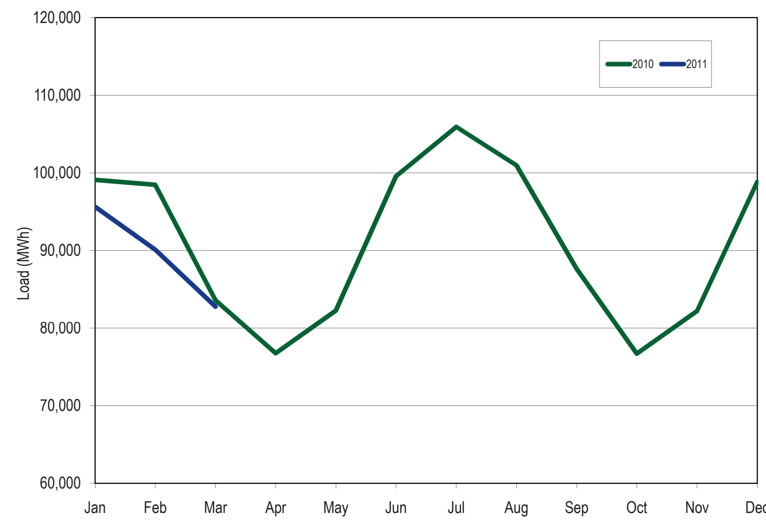
PJM Day-Ahead, Annual Average Load

Table 2-29 PJM day-ahead average load: Calendar years 2000 through March 2011 (See 2010 SOM, Table 2-31)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	33,045	33,217	6,850	NA	NA	NA
2001	33,318	32,812	6,489	0.8%	(1.2%)	(5.3%)
2002	42,131	40,720	10,130	26.4%	24.1%	56.1%
2003	44,340	44,368	7,883	5.2%	9.0%	(22.2%)
2004	61,034	58,544	16,318	37.7%	32.0%	107.0%
2005	92,002	90,424	17,381	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)
2009	88,707	88,833	14,896	(7.1%)	(6.4%)	(3.5%)
2010	90,985	88,925	17,014	2.6%	0.1%	14.2%
2011	89,478	89,561	11,157	(1.7%)	0.7%	(34.4%)

PJM Day-Ahead, Monthly Average Load

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



Real-Time and Day-Ahead Load

Table 2-30 Cleared day-ahead and real-time load (MWh): January through March 2011 (See 2010 SOM, Table 2-32)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bid
Average	77,744	859	10,875	89,478	81,018	8,460	(2,415)
Median	77,437	852	10,734	89,561	80,991	8,570	(2,164)
Standard deviation	9,641	189	1,894	11,157	10,273	884	(1,011)
Peak average	83,588	950	11,877	96,416	87,187	9,229	(2,648)
Peak median	83,266	951	11,792	96,314	86,883	9,431	(2,362)
Peak standard deviation	7,314	176	1,603	8,069	7,700	369	(1,234)
Off peak average	72,472	777	9,970	83,219	75,453	7,766	(2,204)
Off peak median	72,228	772	9,769	82,878	74,949	7,929	(1,840)
Off peak standard deviation	8,365	161	1,668	9,770	9,055	716	(953)

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

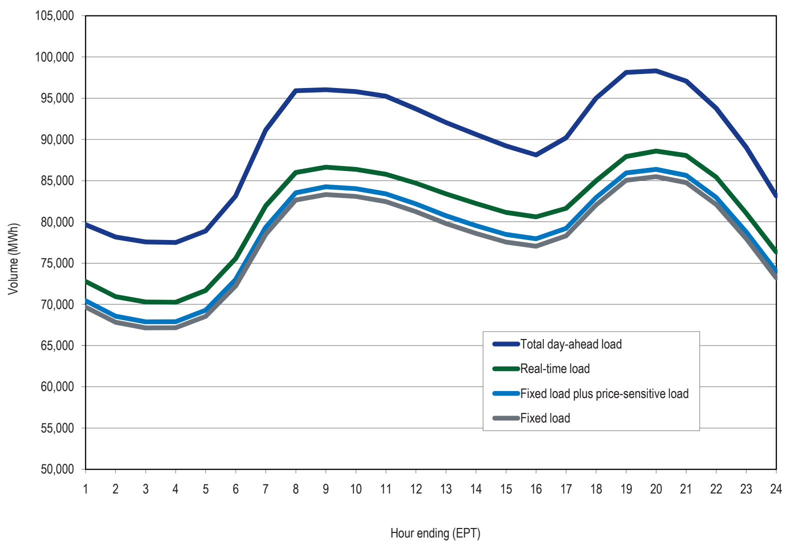
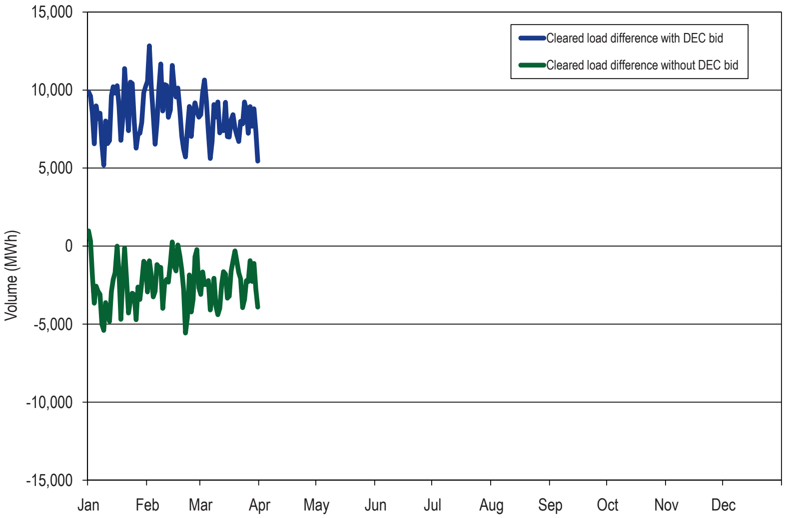


Figure 2-10 Difference between day-ahead and real-time loads (Average daily volumes): January through March 2011 (See 2010 SOM, Figure 2-10)



Real-Time and Day-Ahead Generation

Table 2-31 Day-ahead and real-time generation (MWh): January through March 2011 (See 2010 SOM, Table 2-33)

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	84,725	7,947	92,672	83,505	1,220	9,168
Median	85,010	7,844	92,948	83,643	1,367	9,305
Standard deviation	10,911	1,134	11,463	10,116	795	1,347
Peak average	91,389	8,554	99,943	89,689	1,700	10,254
Peak median	91,319	8,412	99,787	89,381	1,938	10,406
Peak standard deviation	7,869	1,037	8,193	7,530	339	663
Off peak average	78,713	7,400	86,113	77,925	788	8,188
Off peak median	78,214	7,398	85,782	77,614	600	8,168
Off peak standard deviation	9,717	920	9,934	8,825	892	1,110

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

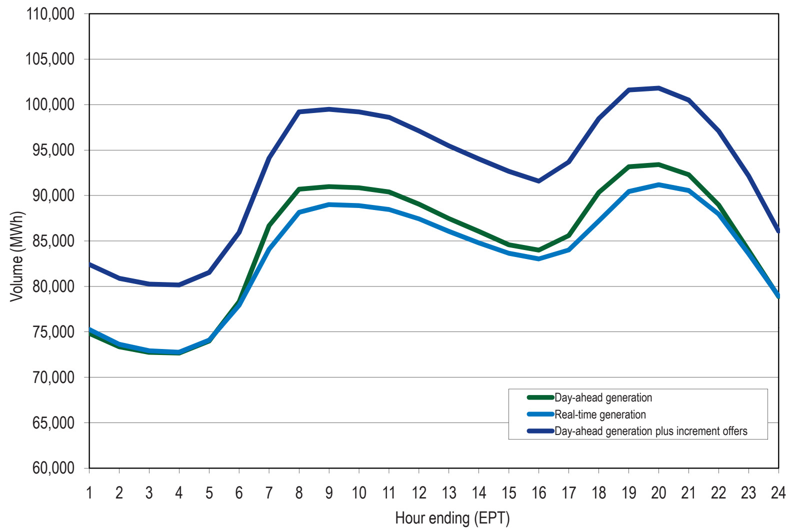
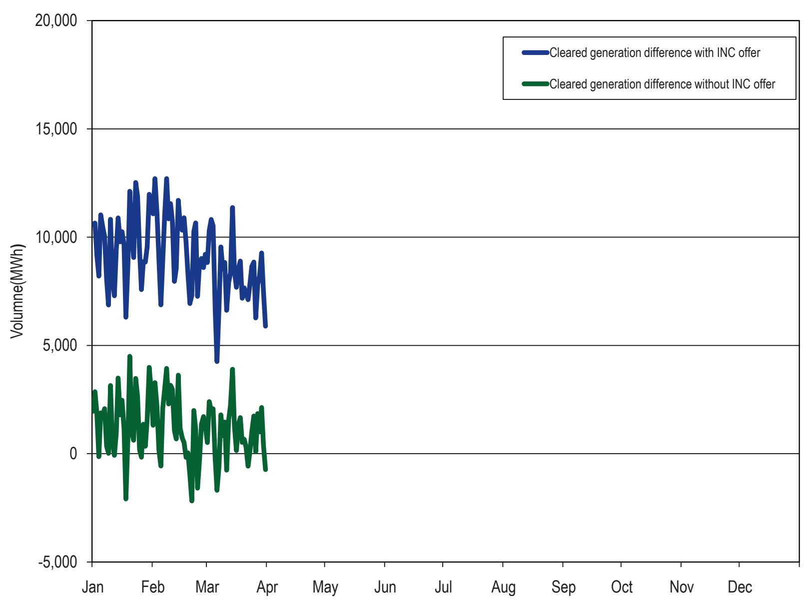


Figure 2-12 Difference between day-ahead and real-time generation (Average daily volumes): January through March 2011 (See 2010 SOM, Figure 2-12)



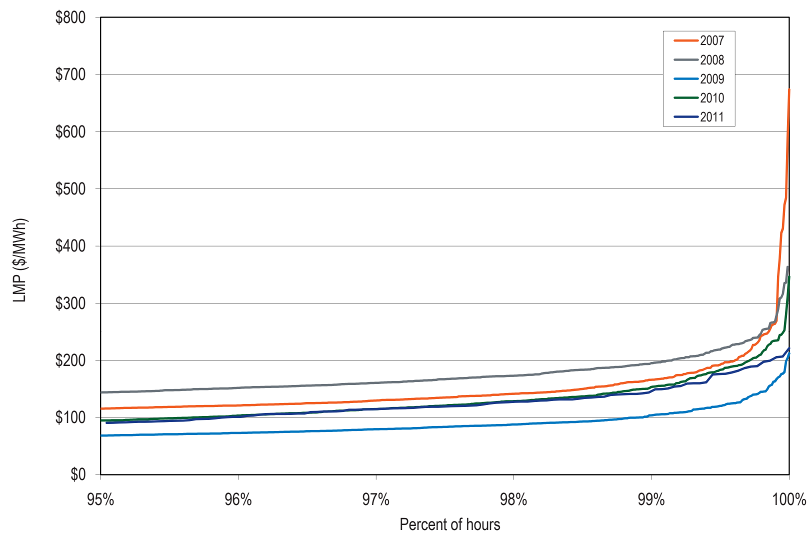
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

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



PJM Real-Time, Annual Average LMP

Table 2-32 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 through March 2011 (See 2010 SOM, Table 2-34)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$44.76	$38.14	$23.10	(0.2%)	3.4%	(11.9%)

Table 2-33 PJM real-time, simple average LMP (Dollars per MWh): January through March 2007 through 2011 (See 2010 SOM, Table 2-34)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2007 (Jan - Mar)	$55.34	$47.15	$33.29	NA	NA	NA
2008 (Jan - Mar)	$66.75	$57.05	$35.54	20.6%	21.0%	6.8%
2009 (Jan - Mar)	$47.29	$40.56	$21.99	(29.2%)	(28.9%)	(38.1%)
2010 (Jan - Mar)	$44.13	$37.82	$21.87	(6.7%)	(6.8%)	(0.6%)
2011 (Jan - Mar)	$44.76	$38.14	$23.10	1.4%	0.8%	5.6%

Zonal Real-Time, Annual Average LMP

Table 2-34 Zonal real-time, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-35)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AECO	$48.31	$51.89	$3.59	7.4%
AEP	$39.41	$38.55	($0.86)	(2.2%)
AP	$43.67	$44.46	$0.78	1.8%
BGE	$50.44	$51.01	$0.57	1.1%
ComEd	$34.64	$34.40	($0.24)	(0.7%)
DAY	$38.69	$38.36	($0.33)	(0.9%)
DLCO	$39.65	$36.65	($3.01)	(7.6%)
Dominion	$49.43	$48.76	($0.67)	(1.4%)
DPL	$49.01	$51.24	$2.23	4.5%
JCPL	$47.96	$51.84	$3.88	8.1%
Met-Ed	$47.27	$49.36	$2.09	4.4%
PECO	$47.54	$50.57	$3.03	6.4%
PENELEC	$41.83	$44.44	$2.61	6.2%
Pepco	$50.44	$50.63	$0.20	0.4%
PPL	$46.66	$50.54	$3.89	8.3%
PSEG	$49.91	$52.64	$2.72	5.5%
RECO	$46.66	$46.94	$0.27	0.6%
PJM	$44.13	$44.76	$0.63	1.4%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-35 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-36)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
Delaware	$48.30	$50.51	$2.20	4.6%
Illinois	$34.64	$34.40	($0.24)	(0.7%)
Indiana	$37.85	$37.37	($0.48)	(1.3%)
Kentucky	$40.21	$38.60	($1.61)	(4.0%)
Maryland	$50.18	$50.68	$0.50	1.0%
Michigan	$38.54	$37.50	($1.04)	(2.7%)
New Jersey	$49.08	$52.21	$3.13	6.4%
North Carolina	$48.01	$46.41	($1.60)	(3.3%)
Ohio	$38.06	$38.01	($0.06)	(0.2%)
Pennsylvania	$45.06	$47.33	$2.27	5.0%
Tennessee	$41.90	$38.90	($3.00)	(7.2%)
Virginia	$48.61	$47.66	($0.95)	(2.0%)
West Virginia	$39.81	$40.00	$0.19	0.5%
District of Columbia	$50.72	$50.84	$0.13	0.2%

Hub Real-Time, Annual Average LMP

Table 2-36 Hub real-time, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-37)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AEP Gen Hub	$36.33	$35.96	($0.37)	(1.0%)
AEP-DAY Hub	$38.26	$37.63	($0.63)	(1.6%)
Chicago Gen Hub	$33.98	$33.44	($0.55)	(1.6%)
Chicago Hub	$34.78	$34.50	($0.28)	(0.8%)
Dominion Hub	$48.75	$47.87	($0.89)	(1.8%)
Eastern Hub	$48.93	$51.59	$2.66	5.4%
N Illinois Hub	$34.47	$34.10	($0.36)	(1.1%)
New Jersey Hub	$48.90	$52.27	$3.37	6.9%
Ohio Hub	$38.22	$37.63	($0.58)	(1.5%)
West Interface Hub	$40.96	$40.60	($0.36)	(0.9%)
Western Hub	$44.54	$45.82	$1.28	2.9%

Real-Time, Load-Weighted, Average LMP

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

Table 2-37 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through March 2011 (See 2010 SOM, Table 2-38)

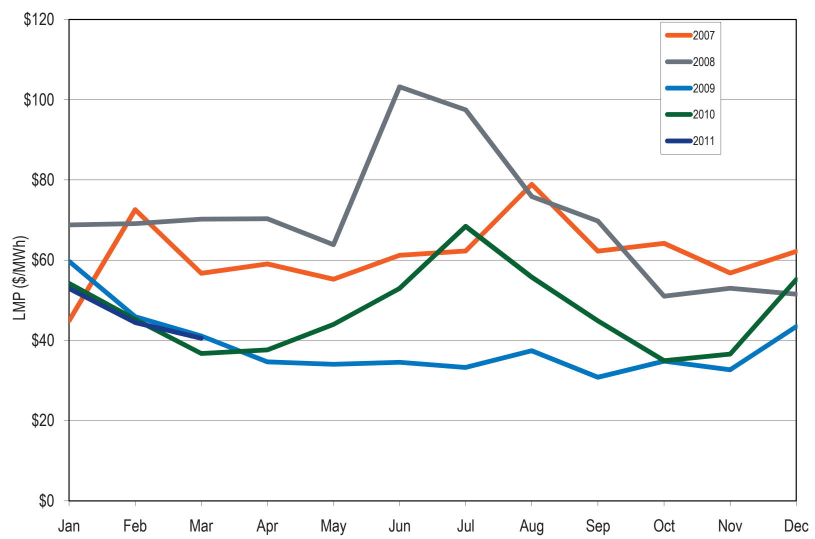
	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$46.35	$39.11	$24.26	(4.1%)	(0.0%)	(16.1%)

Table 2-38 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): January through March 2007 through 2011 (See 2010 SOM, Table 2-38)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2007 (Jan - Mar)	$58.07	$50.60	$34.44	NA	NA	NA
2008 (Jan - Mar)	$69.35	$60.11	$36.56	19.4%	18.8%	6.2%
2009 (Jan - Mar)	$49.60	$42.23	$23.38	(28.5%)	(29.8%)	(36.1%)
2010 (Jan - Mar)	$45.92	$39.01	$22.99	(7.4%)	(7.6%)	(1.7%)
2011 (Jan - Mar)	$46.35	$39.11	$24.26	0.9%	0.3%	5.5%

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

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



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

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

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AECO	$50.19	$54.19	$4.00	8.0%
AEP	$40.81	$39.41	($1.40)	(3.4%)
AP	$45.27	$45.91	$0.64	1.4%
BGE	$53.28	$53.86	$0.58	1.1%
ComEd	$35.85	$35.23	($0.62)	(1.7%)
DAY	$40.06	$39.33	($0.72)	(1.8%)
DLCO	$40.83	$37.14	($3.69)	(9.0%)
Dominion	$52.88	$51.82	($1.06)	(2.0%)
DPL	$51.74	$54.14	$2.40	4.6%
JCPL	$49.95	$54.19	$4.24	8.5%
Met-Ed	$49.14	$51.40	$2.26	4.6%
PECO	$49.39	$52.74	$3.35	6.8%
PENELEC	$42.93	$45.63	$2.70	6.3%
Pepco	$53.24	$53.35	$0.10	0.2%
PPL	$48.69	$52.84	$4.15	8.5%
PSEG	$51.60	$54.43	$2.83	5.5%
RECO	$48.33	$48.68	$0.35	0.7%
PJM	$45.92	$46.35	$0.43	0.9%

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

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

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
Delaware	$50.55	$53.00	$2.45	4.8%
Illinois	$35.85	$35.23	($0.62)	(1.7%)
Indiana	$38.66	$38.00	($0.66)	(1.7%)
Kentucky	$42.29	$39.97	($2.32)	(5.5%)
Maryland	$53.22	$53.64	$0.43	0.8%
Michigan	$39.63	$38.35	($1.28)	(3.2%)
New Jersey	$50.87	$54.22	$3.35	6.6%
North Carolina	$51.81	$49.24	($2.57)	(5.0%)
Ohio	$39.18	$38.72	($0.46)	(1.2%)
Pennsylvania	$46.66	$49.01	$2.35	5.0%
Tennessee	$45.24	$40.74	($4.50)	(9.9%)
Virginia	$51.97	$50.53	($1.44)	(2.8%)
West Virginia	$41.36	$41.05	($0.31)	(0.8%)
District of Columbia	$52.70	$52.71	$0.01	0.0%

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

Fuel Cost

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

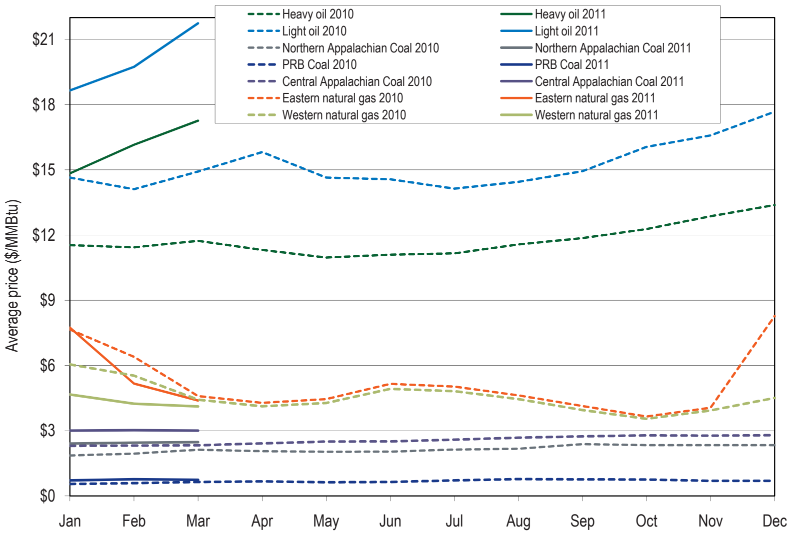


Table 2-41 PJM real-time, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-41)

	2011 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$46.35	$42.73	(7.8%)
	2010 Load-Weighted LMP	**2011 Fuel-Cost-Adjusted, Load-Weighted LMP**	**Change**
Average	$45.92	$42.73	(7.0%)
	2010 Load-Weighted LMP	**2011 Load-Weighted LMP**	**Change**
Average	$45.92	$46.35	0.9%

Components of Real-Time, Load-Weighted LMP

Table 2-42 Components of PJM real-time, load-weighted, average LMP: January through March 2011 (See 2010 SOM, Table 2-42)

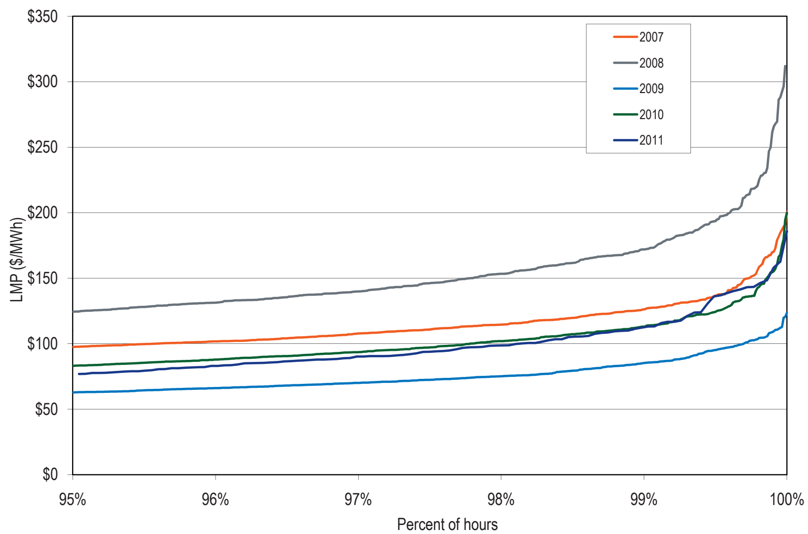
Element	Contribution to LMP	Percent
Coal	$21.54	46.5%
Gas	$14.32	30.9%
10% Cost Adder	$3.93	8.5%
VOM	$2.34	5.0%
NA	$2.29	4.9%
NO_X	$0.59	1.3%
Markup	$0.48	1.0%
Oil	$0.36	0.8%
CO_2	$0.36	0.8%
SO_2	$0.06	0.1%
FMU Adder	$0.04	0.1%
Dispatch Differential	$0.03	0.1%
Unit LMP Differential	$0.02	0.0%
M2M Adder	$0.01	0.0%
Municipal Waste	$0.00	0.0%
Shadow Price Limit Adder	($0.00)	(0.0%)
Wind	($0.01)	(0.0%)
Total	$46.35	100.0%

Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

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



PJM Day-Ahead, Annual Average LMP

Table 2-43 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 through March 2011 (See 2010 SOM, Table 2-43)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$45.60	$41.10	$16.82	2.3%	2.8%	(10.6%)

Table 2-44 PJM day-ahead, simple average LMP (Dollars per MWh): January through March 2007 through 2011 (See 2010 SOM, Table 2-43)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2007 (Jan - Mar)	$52.76	$49.43	$22.59	NA	NA	NA
2008 (Jan - Mar)	$66.10	$62.57	$23.90	25.3%	26.6%	5.8%
2009 (Jan - Mar)	$47.41	$43.43	$16.85	(28.3%)	(30.6%)	(29.5%)
2010 (Jan - Mar)	$46.13	$41.99	$15.93	(2.7%)	(3.3%)	(5.5%)
2011 (Jan - Mar)	$45.60	$41.10	$16.82	(1.2%)	(2.1%)	5.6%

Zonal Day-Ahead, Annual Average LMP

Table 2-45 Zonal day-ahead, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-44)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AECO	$50.98	$53.79	$2.80	5.5%
AEP	$40.38	$38.88	($1.50)	(3.7%)
AP	$45.11	$45.20	$0.09	0.2%
BGE	$53.96	$52.74	($1.22)	(2.3%)
ComEd	$35.75	$34.32	($1.43)	(4.0%)
DAY	$39.22	$38.53	($0.69)	(1.8%)
DLCO	$39.71	$36.62	($3.09)	(7.8%)
Dominion	$53.30	$50.66	($2.64)	(5.0%)
DPL	$51.32	$54.16	$2.84	5.5%
JCPL	$51.09	$54.22	$3.14	6.1%
Met-Ed	$50.23	$51.43	$1.20	2.4%
PECO	$50.53	$53.42	$2.89	5.7%
PENELEC	$44.51	$45.12	$0.61	1.4%
Pepco	$54.23	$52.35	($1.88)	(3.5%)
PPL	$49.71	$52.46	$2.75	5.5%
PSEG	$52.23	$55.55	$3.33	6.4%
RECO	$50.69	$51.83	$1.14	2.3%
PJM	$46.13	$45.60	($0.54)	(1.2%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-46 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-45)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
Delaware	$50.73	$53.27	$2.53	5.0%
Illinois	$35.75	$34.32	($1.43)	(4.0%)
Indiana	$38.60	$37.72	($0.88)	(2.3%)
Kentucky	$40.81	$38.95	($1.85)	(4.5%)
Maryland	$53.50	$52.49	($1.02)	(1.9%)
Michigan	$39.18	$37.97	($1.21)	(3.1%)
New Jersey	$51.73	$54.89	$3.16	6.1%
North Carolina	$51.71	$48.94	($2.76)	(5.3%)
Ohio	$38.60	$38.00	($0.61)	(1.6%)
Pennsylvania	$47.48	$48.98	$1.50	3.2%
Tennessee	$43.18	$39.25	($3.93)	(9.1%)
Virginia	$52.25	$49.46	($2.79)	(5.3%)
West Virginia	$40.63	$40.59	($0.03)	(0.1%)
District of Columbia	$54.58	$52.47	($2.12)	(3.9%)

Day-Ahead, Load-Weighted, Average LMP

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

Table 2-47 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through March 2011 (See 2010 SOM, Table 2-46)

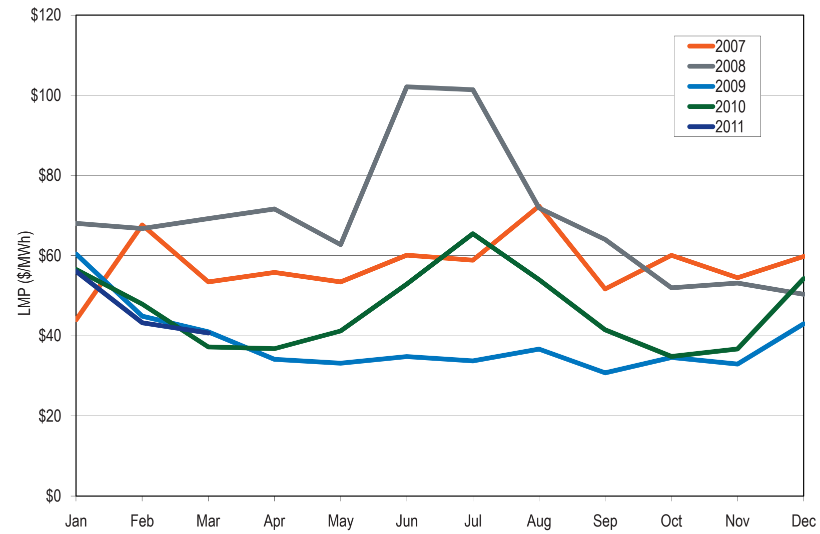
	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$47.14	$42.49	$17.73	(1.1%)	1.0%	(13.9%)

Table 2-48 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through March 2007 through 2011 (See 2010 SOM, Table 2-46)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2007 (Jan - Mar)	$54.87	$51.89	$23.16	NA	NA	NA
2008 (Jan - Mar)	$68.00	$64.70	$24.35	23.9%	24.7%	5.1%
2009 (Jan - Mar)	$49.44	$44.85	$17.54	(27.3%)	(30.7%)	(28.0%)
2010 (Jan - Mar)	$47.77	$43.62	$16.52	(3.4%)	(2.7%)	(5.8%)
2011 (Jan - Mar)	$47.14	$42.49	$17.73	(1.3%)	(2.6%)	7.3%

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

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



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-49 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-47)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AECO	$53.66	$56.13	$2.48	4.6%
AEP	$41.63	$39.70	($1.93)	(4.6%)
AP	$46.61	$46.59	($0.02)	(0.0%)
BGE	$56.54	$55.47	($1.07)	(1.9%)
ComEd	$36.57	$34.93	($1.64)	(4.5%)
DAY	$40.48	$39.41	($1.08)	(2.7%)
DLCO	$41.01	$37.25	($3.76)	(9.2%)
Dominion	$56.74	$53.76	($2.98)	(5.2%)
DPL	$53.72	$57.23	$3.51	6.5%
JCPL	$52.89	$56.60	$3.70	7.0%
Met-Ed	$52.07	$53.28	$1.21	2.3%
PECO	$52.47	$56.02	$3.54	6.8%
PENELEC	$45.47	$46.51	$1.05	2.3%
Pepco	$56.02	$54.87	($1.16)	(2.1%)
PPL	$51.86	$54.72	$2.86	5.5%
PSEG	$53.75	$57.49	$3.74	7.0%
RECO	$53.11	$53.93	$0.82	1.5%
PJM	$47.77	$47.14	($0.63)	(1.3%)

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

Table 2-50 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-48)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
Delaware	$53.05	$55.95	$2.90	5.5%
Illinois	$36.57	$34.93	($1.64)	(4.5%)
Indiana	$39.57	$38.35	($1.22)	(3.1%)
Kentucky	$42.19	$40.06	($2.13)	(5.1%)
Maryland	$55.89	$55.23	($0.66)	(1.2%)
Michigan	$39.96	$38.64	($1.32)	(3.3%)
New Jersey	$53.46	$56.98	$3.52	6.6%
North Carolina	$54.78	$52.45	($2.32)	(4.2%)
Ohio	$39.67	$38.69	($0.98)	(2.5%)
Pennsylvania	$49.00	$50.78	$1.79	3.6%
Tennessee	$45.10	$40.63	($4.47)	(9.9%)
Virginia	$55.39	$52.25	($3.14)	(5.7%)
West Virginia	$41.98	$41.51	($0.47)	(1.1%)
District of Columbia	$55.86	$54.61	($1.25)	(2.2%)

Components of Day-Ahead, Load-Weighted LMP

Table 2-51 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-49)

Element	Contribution to LMP	Percent
Coal	$12.89	27.3%
DEC	$11.58	24.6%
INC	$7.99	17.0%
Natural gas	$6.81	14.4%
Transaction	$3.56	7.6%
10% Cost Adder	$2.16	4.6%
Price Sensitive Demand	$1.28	2.7%
VOM	$1.23	2.6%
NO_x	$0.32	0.7%
CO_2	$0.22	0.5%
Oil	$0.12	0.2%
SO_2	$0.03	0.1%
Constrained Off	($0.00)	(0.0%)
Markup	($0.98)	(2.1%)
NA	($0.08)	(0.2%)
Total	$47.14	100.0%

Marginal Losses

Table 2-52 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through March 2011 (See 2010 SOM, Table 2-50)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$44.83	$44.72	$0.07	$0.04
2011 (Jan - Mar)	$44.76	$44.70	$0.03	$0.02

Table 2-53 Zonal real-time, simple average LMP components (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-51)

	2010 (Jan - Mar)				2011 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$48.31	$44.02	$1.73	$2.55	$51.89	$44.70	$4.81	$2.38
AEP	$39.41	$44.02	($2.98)	($1.64)	$38.55	$44.70	($4.46)	($1.69)
AP	$43.67	$44.02	($0.33)	($0.02)	$44.46	$44.70	($0.31)	$0.06
BGE	$50.44	$44.02	$4.06	$2.36	$51.01	$44.70	$4.19	$2.12
ComEd	$34.64	$44.02	($6.15)	($3.23)	$34.40	$44.70	($7.15)	($3.15)
DAY	$38.69	$44.02	($4.15)	($1.18)	$38.36	$44.70	($5.16)	($1.18)
DLCO	$39.65	$44.02	($2.67)	($1.70)	$36.65	$44.70	($6.76)	($1.29)
Dominion	$49.43	$44.02	$4.52	$0.89	$48.76	$44.70	$3.36	$0.70
DPL	$49.01	$44.02	$2.18	$2.81	$51.24	$44.70	$3.53	$3.01
JCPL	$47.96	$44.02	$1.34	$2.59	$51.84	$44.70	$4.48	$2.67
Met-Ed	$47.27	$44.02	$1.71	$1.54	$49.36	$44.70	$3.46	$1.20
PECO	$47.54	$44.02	$1.72	$1.80	$50.57	$44.70	$3.95	$1.91
PENELEC	$41.83	$44.02	($1.93)	($0.26)	$44.44	$44.70	($0.72)	$0.46
Pepco	$50.44	$44.02	$4.86	$1.56	$50.63	$44.70	$4.64	$1.29
PPL	$46.66	$44.02	$1.47	$1.16	$50.54	$44.70	$4.68	$1.16
PSEG	$49.91	$44.02	$3.31	$2.58	$52.64	$44.70	$5.33	$2.61
RECO	$46.66	$44.02	$0.44	$2.20	$46.94	$44.70	($0.16)	$2.39

Table 2-54 Hub real-time, simple average LMP components (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-52)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.96	$44.70	($5.63)	($3.12)
AEP-DAY Hub	$37.63	$44.70	($5.15)	($1.92)
Chicago Gen Hub	$33.44	$44.70	($7.53)	($3.73)
Chicago Hub	$34.50	$44.70	($7.07)	($3.12)
Dominion Hub	$47.87	$44.70	$2.91	$0.25
Eastern Hub	$51.59	$44.70	$3.74	$3.15
N Illinois Hub	$34.10	$44.70	($7.22)	($3.37)
New Jersey Hub	$52.27	$44.70	$4.99	$2.57
Ohio Hub	$37.63	$44.70	($5.16)	($1.90)
West Interface Hub	$40.60	$44.70	($2.80)	($1.30)
Western Hub	$45.82	$44.70	$1.05	$0.06

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

Table 2-55 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-53)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$54.19	$46.25	$5.42	$2.52
AEP	$39.41	$46.16	($4.99)	($1.76)
AP	$45.91	$46.34	($0.48)	$0.05
BGE	$53.86	$46.70	$4.94	$2.23
ComEd	$35.23	$45.79	($7.33)	($3.23)
DAY	$39.33	$46.25	($5.71)	($1.21)
DLCO	$37.14	$45.88	($7.38)	($1.36)
Dominion	$51.82	$46.85	$4.23	$0.74
DPL	$54.14	$46.75	$4.14	$3.25
JCPL	$54.19	$46.35	$5.02	$2.82
Met-Ed	$51.40	$46.26	$3.87	$1.28
PECO	$52.74	$46.31	$4.41	$2.02
PENELEC	$45.63	$46.01	($0.84)	$0.46
Pepco	$53.35	$46.61	$5.39	$1.35
PPL	$52.84	$46.42	$5.18	$1.24
PSEG	$54.43	$45.99	$5.71	$2.73
RECO	$48.68	$46.12	$0.05	$2.51
PJM	$46.35	$46.30	$0.03	$0.03

Table 2-56 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 through March 2011 (See 2010 SOM, Table 2-54)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)
2010	$44.57	$44.61	$0.03	($0.06)
2011 (Jan - Mar)	$45.60	$45.81	($0.11)	($0.11)

Table 2-57 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through March 2010 to 2011 (See 2010 SOM, Table 2-55)

	2010 (Jan - Mar)				2011 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$50.98	$46.10	$2.11	$2.77	$53.79	$45.81	$5.01	$2.97
AEP	$40.38	$46.10	($3.49)	($2.23)	$38.88	$45.81	($4.66)	($2.27)
AP	$45.11	$46.10	($1.04)	$0.05	$45.20	$45.81	($0.52)	($0.09)
BGE	$53.96	$46.10	$4.64	$3.22	$52.74	$45.81	$4.57	$2.36
ComEd	$35.75	$46.10	($6.12)	($4.23)	$34.32	$45.81	($7.78)	($3.70)
DAY	$39.22	$46.10	($4.79)	($2.09)	$38.53	$45.81	($5.42)	($1.85)
DLCO	$39.71	$46.10	($4.39)	($2.00)	$36.62	$45.81	($7.42)	($1.76)
Dominion	$53.30	$46.10	$5.61	$1.58	$50.66	$45.81	$3.73	$1.12
DPL	$51.32	$46.10	$2.36	$2.85	$54.16	$45.81	$4.69	$3.67
JCPL	$51.09	$46.10	$1.77	$3.21	$54.22	$45.81	$5.01	$3.41
Met-Ed	$50.23	$46.10	$2.32	$1.81	$51.43	$45.81	$4.29	$1.33
PECO	$50.53	$46.10	$2.14	$2.28	$53.42	$45.81	$5.05	$2.56
PENELEC	$44.51	$46.10	($1.97)	$0.37	$45.12	$45.81	($0.91)	$0.22
Pepco	$54.23	$46.10	$5.69	$2.44	$52.35	$45.81	$4.85	$1.69
PPL	$49.71	$46.10	$2.23	$1.38	$52.46	$45.81	$5.42	$1.23
PSEG	$52.23	$46.10	$2.76	$3.37	$55.55	$45.81	$6.16	$3.58
RECO	$50.69	$46.10	$1.69	$2.90	$51.83	$45.81	$2.92	$3.10

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

Table 2-58 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-56)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$56.13	$47.42	$5.58	$3.13
AEP	$39.70	$47.24	($5.17)	($2.37)
AP	$46.59	$47.42	($0.72)	($0.11)
BGE	$55.47	$47.74	$5.23	$2.50
ComEd	$34.93	$46.71	($8.01)	($3.77)
DAY	$39.41	$47.25	($5.91)	($1.93)
DLCO	$37.25	$46.94	($7.85)	($1.84)
Dominion	$53.76	$48.01	$4.52	$1.23
DPL	$57.23	$47.90	$5.41	$3.92
JCPL	$56.60	$47.47	$5.54	$3.59
Met-Ed	$53.28	$47.21	$4.66	$1.41
PECO	$56.02	$47.54	$5.76	$2.72
PENELEC	$46.51	$47.39	($1.10)	$0.23
Pepco	$54.87	$47.59	$5.48	$1.79
PPL	$54.72	$47.54	$5.88	$1.30
PSEG	$57.49	$47.21	$6.55	$3.73
RECO	$53.93	$47.42	$3.27	$3.25
PJM	$47.14	$47.36	($0.11)	($0.11)

Marginal Loss Costs and Loss Credits

Table 2-59 Marginal loss costs and loss credits: Calendar years 2007 through March 2011[10] (See 2010 SOM, Table 2-57)

	Total Marginal Loss Costs	Loss Credits	Percent
2007	$1,246,944,931	$630,277,662	50.5%
2008	$2,493,333,212	$1,309,286,301	52.5%
2009	$1,268,085,226	$639,684,849	50.4%
2010	$1,634,719,184	$836,683,849	51.2%
2011 (Jan - Mar)	$409,597,112	$200,148,617	48.9%

10 2007 only includes data from June 1, 2007 through December 31, 2007. PJM began including marginal losses in economic dispatch and LMP models on June 1, 2007.

Monthly Marginal Loss Costs

Table 2-60 Marginal loss costs by type (Dollars (Millions)): January through March 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
Total	$91.4	($301.7)	$26.0	$419.1	$7.9	$6.3	($11.1)	($9.5)	$409.6

Zonal Marginal Loss Costs

Table 2-61 Marginal loss costs by control zone and type (Dollars (Millions)): January through March 2011 (See 2010 SOM, Table 2-59)

	Marginal Loss Costs by Control Zone (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$7.9	$1.6	$0.2	$6.4	$0.2	($0.3)	($0.1)	$0.3	$6.7
AEP	($21.7)	($109.0)	$8.8	$96.0	$0.4	$2.9	($2.3)	($4.8)	$91.3
AP	($1.2)	($30.8)	$2.5	$32.2	$0.8	$1.4	($1.2)	($1.8)	$30.4
BGE	$18.5	$4.7	$1.3	$15.1	$0.8	($0.5)	($1.0)	$0.3	$15.4
ComEd	($63.0)	($130.8)	$4.1	$72.0	$6.4	$1.7	$0.7	$5.4	$77.3
DAY	($1.5)	($16.8)	$1.2	$16.5	($0.1)	$1.2	($0.5)	($1.7)	$14.7
DLCO	($5.6)	($10.6)	$0.2	$5.2	($0.6)	$0.0	($0.1)	($0.7)	$4.4
Dominion	$26.0	($13.1)	$2.2	$41.4	$0.7	($0.3)	($1.3)	($0.3)	$41.1
DPL	$19.8	$2.5	$0.4	$17.7	($1.0)	($0.3)	($0.3)	($1.1)	$16.6
JCPL	$21.0	$7.5	$0.1	$13.5	($0.1)	($0.1)	($0.1)	($0.1)	$13.5
Met-Ed	$5.5	$0.9	$0.0	$4.6	$0.1	($0.2)	($0.0)	$0.2	$4.8
PECO	$25.2	$11.5	$0.4	$14.1	($0.3)	($0.0)	($0.3)	($0.6)	$13.6
PENELEC	($3.1)	($20.8)	($0.1)	$17.6	$0.5	$0.3	($0.0)	$0.2	$17.8
Pepco	$17.8	$4.6	$1.6	$14.8	($0.6)	($0.6)	($1.3)	($1.3)	$13.5
PJM	($2.2)	($12.6)	($1.5)	$8.9	($0.0)	($3.0)	($0.5)	$2.5	$11.4
PPL	$13.7	($1.1)	$0.8	$15.6	$1.2	$0.4	($0.2)	$0.6	$16.2
PSEG	$33.2	$10.5	$3.8	$26.5	($0.4)	$3.9	($2.5)	($6.8)	$19.7
RECO	$1.2	$0.2	$0.1	$1.0	($0.0)	($0.2)	($0.0)	$0.1	$1.1
Total	$91.4	($301.7)	$26.0	$419.1	$7.9	$6.3	($11.1)	($9.5)	$409.6

Table 2-62 Monthly marginal loss costs by control zone (Dollars (Millions)): January through March 2011 (See 2010 SOM, Table 2-60)

	Marginal Loss Costs by Control Zone (Millions)			
	Jan	Feb	Mar	Grand Total
AECO	$2.9	$2.0	$1.8	$6.7
AEP	$41.9	$25.6	$23.8	$91.3
AP	$14.3	$8.4	$7.7	$30.4
BGE	$6.5	$5.0	$3.9	$15.4
ComEd	$32.3	$21.9	$23.1	$77.3
DAY	$5.2	$5.0	$4.5	$14.7
DLCO	$2.2	$1.6	$0.7	$4.4
Dominion	$19.8	$11.6	$9.7	$41.1
DPL	$7.7	$5.3	$3.6	$16.6
JCPL	$6.2	$4.1	$3.1	$13.5
Met-Ed	$2.1	$1.4	$1.4	$4.8
PECO	$6.6	$3.5	$3.5	$13.6
PENELEC	$8.9	$5.3	$3.6	$17.8
Pepco	$5.9	$3.7	$3.9	$13.5
PJM	$6.9	$4.3	$0.2	$11.4
PPL	$8.6	$4.7	$3.0	$16.2
PSEG	$7.3	$6.1	$6.3	$19.7
RECO	$0.5	$0.3	$0.3	$1.1
Total	$185.7	$119.9	$104.0	$409.6

Virtual Offers and Bids

Table 2-63 Monthly volume of cleared and submitted INCs, DECs: January through March 2011 (See 2010 SOM, Table 2-61)

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	8,137	14,299	218	1,077	11,135	17,917	224	963
Feb	8,532	16,263	215	1,672	11,076	17,355	230	1,034
Mar	7,230	13,164	201	1,059	10,435	16,343	219	982
Annual	7,948	14,520	211	1,256	10,876	17,201	224	991

Table 2-64 Type of day-ahead marginal units: January through March 2011 (See 2010 SOM, Table 2-62)

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	11.2%	64.7%	13.5%	10.2%	0.3%
Feb	10.1%	68.1%	12.7%	8.8%	0.3%
Mar	9.5%	67.2%	15.3%	7.6%	0.3%
Annual	10.3%	66.6%	13.9%	8.9%	0.3%

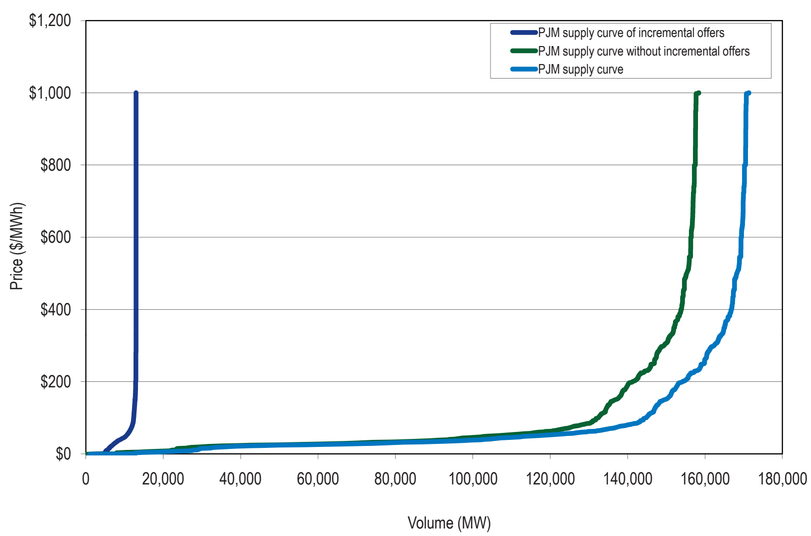
Table 2-65 PJM virtual bids by type of bid parent organization (MW): January through March 2011 (See 2010 SOM, Table 2-63)

	Category	Total Virtual Bids MW	Percentage
2011	Financial	35,014,214	51.1%
2011	Physical	33,469,428	48.9%
2011	Total	68,483,641	100.0%

Table 2-66 PJM virtual offers and bids by top ten aggregates (MW): January through March 2011 (See 2010 SOM, Table 2-64)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	6,426,945	6,902,555	13,329,499
N ILLINOIS HUB	HUB	2,625,577	4,527,187	7,152,764
AEP-DAYTON HUB	HUB	1,480,676	1,641,866	3,122,541
SOUTHIMP	INTERFACE	1,731,983	0	1,731,983
MISO	INTERFACE	68,374	1,244,714	1,313,088
PECO	ZONE	296,203	999,453	1,295,656
PPL	ZONE	104,239	993,763	1,098,001
IMO	INTERFACE	808,906	85,891	894,798
ComEd	ZONE	680,972	165,165	846,137
BGE	ZONE	48,094	762,176	810,270
Top ten total		14,271,967	17,322,770	31,594,736
PJM total		31,347,701	37,135,940	68,483,641
Top ten total as percent of PJM total		46.0%	47.0%	46.0%

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



Price Convergence

Table 2-67 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-65)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$45.60	$44.76	($0.84)	(1.9%)
Median	$41.10	$38.14	($2.96)	(7.8%)
Standard deviation	$16.82	$23.10	$6.27	27.2%
Peak average	$50.24	$49.26	($0.98)	(2.0%)
Peak median	$45.77	$42.16	($3.61)	(8.6%)
Peak standard deviation	$16.21	$23.06	$6.86	29.7%
Peak average	$41.41	$40.70	($0.71)	(1.7%)
Peak median	$36.85	$34.85	($2.00)	(5.7%)
Peak standard deviation	$16.27	$22.37	$6.10	27.3%

Table 2-68 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 through March 2011 (See 2010 SOM, Table 2-66)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$31.97	$30.36	($1.61)	(5.0%)
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	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$45.60	$44.76	($0.84)	(1.8%)

Table 2-69 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2007 through March 2011 (See 2010 SOM, Table 2-67)

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	1	0.05%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	17	0.83%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	1,464	68.64%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	619	97.31%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	51	99.68%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	6	99.95%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	1	100.00%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	0	100.00%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	100.00%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	100.00%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

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

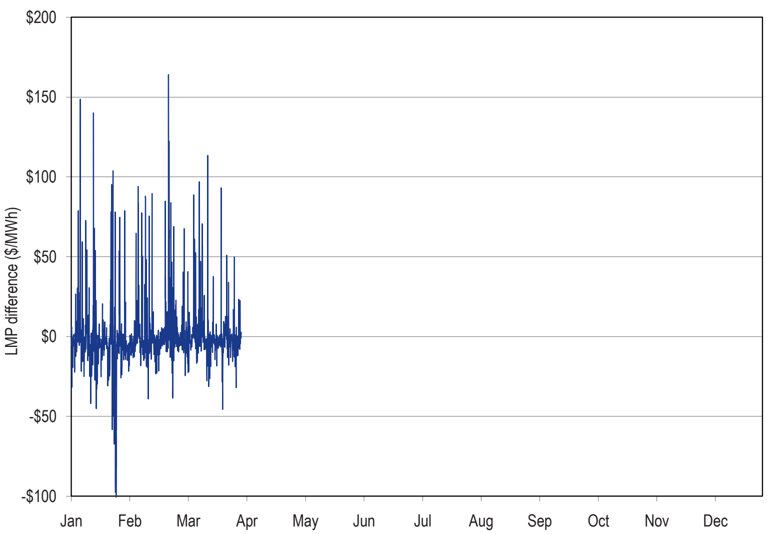


Figure 2-20 Monthly simple average of real-time minus day-ahead LMP: January through March 2011 (See 2010 SOM, Figure 2-20)

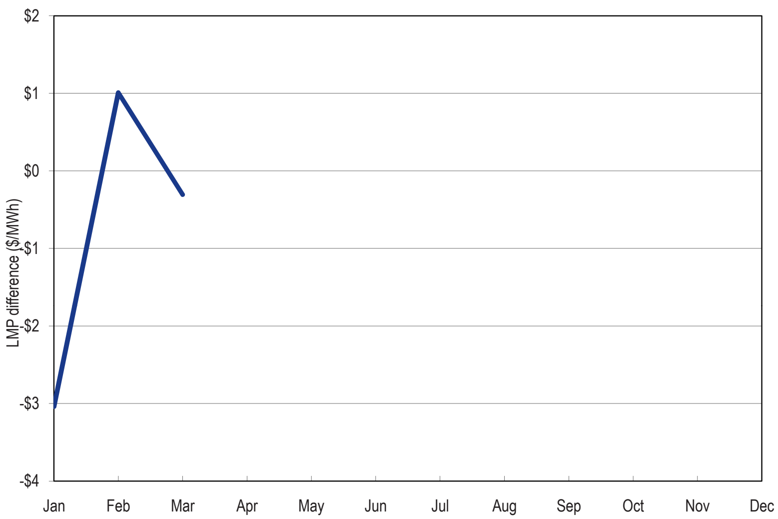
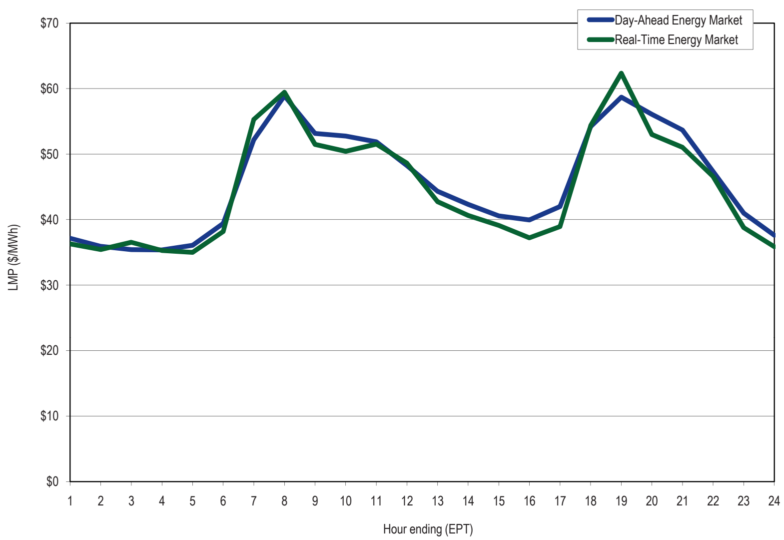


Figure 2-21 PJM system simple hourly average LMP: January through March 2011 (See 2010 SOM, Figure 2-21)



Zonal Price Convergence

Table 2-70 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-68)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$53.79	$51.89	($1.89)	(3.5%)
AEP	$38.88	$38.55	($0.33)	(0.9%)
AP	$45.20	$44.46	($0.74)	(1.6%)
BGE	$52.74	$51.01	($1.73)	(3.3%)
ComEd	$34.32	$34.40	$0.08	0.2%
DAY	$38.53	$38.36	($0.17)	(0.4%)
DLCO	$36.62	$36.65	$0.02	0.1%
Dominion	$50.66	$48.76	($1.90)	(3.7%)
DPL	$54.16	$51.24	($2.92)	(5.4%)
JCPL	$54.22	$51.84	($2.38)	(4.4%)
Met-Ed	$51.43	$49.36	($2.07)	(4.0%)
PECO	$53.42	$50.57	($2.85)	(5.3%)
PENELEC	$45.12	$44.44	($0.68)	(1.5%)
Pepco	$52.35	$50.63	($1.71)	(3.3%)
PPL	$52.46	$50.54	($1.92)	(3.7%)
PSEG	$55.55	$52.64	($2.91)	(5.2%)
RECO	$51.83	$46.94	($4.89)	(9.4%)

Price Convergence by Jurisdiction

Table 2-71 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-69)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$53.27	$50.51	($2.76)	(5.2%)
Illinois	$34.32	$34.40	$0.08	0.2%
Indiana	$37.72	$37.37	($0.35)	(0.9%)
Kentucky	$38.95	$38.60	($0.36)	(0.9%)
Maryland	$52.49	$50.68	($1.81)	(3.5%)
Michigan	$37.97	$37.50	($0.47)	(1.2%)
New Jersey	$54.89	$52.21	($2.67)	(4.9%)
North Carolina	$48.94	$46.41	($2.54)	(5.2%)
Ohio	$38.00	$38.01	$0.01	0.0%
Pennsylvania	$48.98	$47.33	($1.65)	(3.4%)
Tennessee	$39.25	$38.90	($0.35)	(0.9%)
Virginia	$49.46	$47.66	($1.80)	(3.6%)
West Virginia	$40.59	$40.00	($0.59)	(1.5%)
District of Columbia	$52.47	$50.84	($1.62)	(3.1%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-72 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2010 to March 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%						
May	11.6%	19.9%	68.5%						
Jun	10.4%	19.0%	70.5%						
Jul	9.8%	19.5%	70.7%						
Aug	10.6%	20.5%	68.9%						
Sep	12.0%	22.3%	65.7%						
Oct	13.0%	25.1%	61.9%						
Nov	12.8%	22.7%	64.5%						
Dec	11.5%	21.8%	66.7%						
Annual	11.8%	20.2%	68.0%	10.1%	28.7%	61.2%	(1.7%)	8.4%	(6.8%)

Day-Ahead Load and Spot Market

Table 2-73 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2010 to March 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%	5.1%	27.0%	67.9%	0.5%	9.2%	(9.7%)
Feb	4.6%	18.4%	77.0%	5.9%	26.5%	67.6%	1.3%	8.1%	(9.4%)
Mar	4.8%	18.4%	76.8%	6.2%	27.6%	66.2%	1.4%	9.1%	(10.6%)
Apr	4.9%	19.1%	76.0%						
May	6.6%	19.0%	74.4%						
Jun	4.6%	18.6%	76.7%						
Jul	4.7%	18.6%	76.6%						
Aug	4.8%	19.3%	75.9%						
Sep	4.6%	20.7%	74.8%						
Oct	4.9%	22.7%	72.4%						
Nov	4.9%	20.7%	74.4%						
Dec	4.6%	19.2%	76.2%						
Annual	4.9%	19.3%	75.8%	5.7%	27.0%	67.3%	0.8%	7.7%	(8.6%)

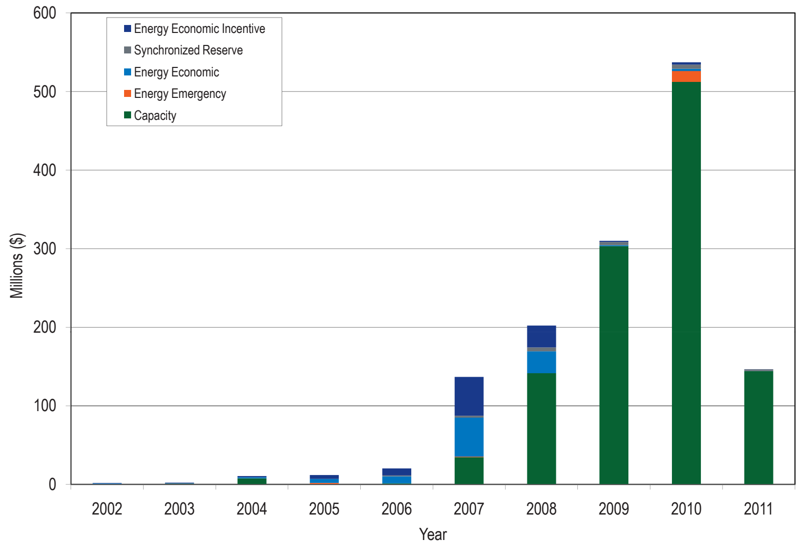
Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-74 Overview of Demand Side Programs (See 2010 SOM, Table 2-72)

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

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



Economic Program

Table 2-75 Economic Program registration on peak load days: Calendar years 2002 to 2010 and January through March 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
24-Jan-11	1,600	2,445.2

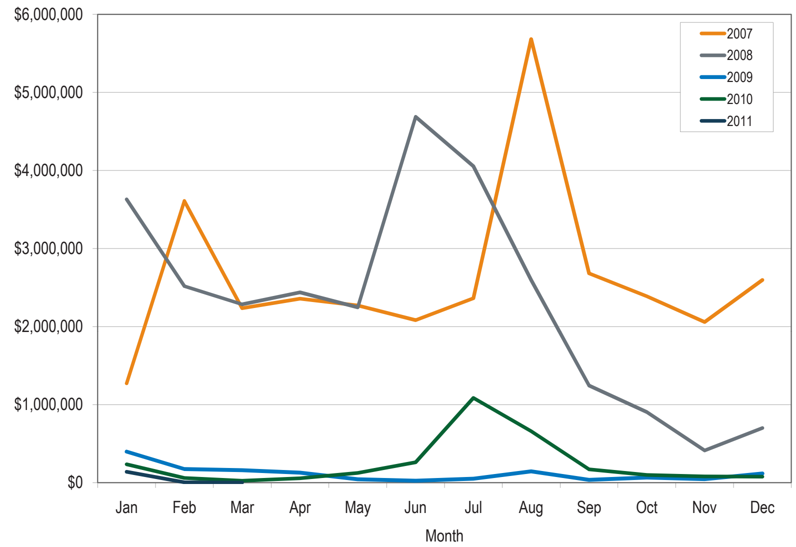
Table 2-76 Economic Program registrations on the last day of the month: January 2008 through March 2011 (See 2010 SOM, Table 2-74)

	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		
May	5,069	3,588	1,250	2,860	1,875	2,819		
Jun	3,112	3,014	1,265	2,461	813	1,608		
Jul	4,542	3,165	1,265	2,445	1,192	2,159		
Aug	4,815	3,232	1,653	2,650	1,616	2,398		
Sep	4,836	3,263	1,879	2,727	1,609	2,447		
Oct	4,846	3,266	1,875	2,730	1,606	2,444		
Nov	4,851	3,271	1,874	2,730	1,605	2,444		
Dec	4,851	3,290	1,853	2,627	1,598	2,439		
Avg.	4,727	3,185	2,508	2,852	1,608	2,435		

Table 2-77 Distinct registrations and sites in the Economic Program: January 24, 2011[11] (See 2010 SOM, Table 2-75)

	Registrations	Sites	MW
AECO	31	42	14.2
AEP	50	56	157.4
AP	54	58	186.5
BGE	57	76	476.4
ComEd	540	1,255	325.5
DAY	9	9	10.9
DLCO	54	59	86.4
Dominion	129	129	434.2
DPL	45	60	101.0
JCPL	47	85	108.0
Met-Ed	59	62	59.3
PECO	215	297	155.1
PENELEC	56	63	60.1
Pepco	37	39	33.5
PPL	135	164	180.3
PSEG	80	201	55.7
RECO	2	7	0.7
Total	1,600	2,662	2,445.2

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



11 Effective July 1, 2009, PJM implemented a new eSuite application, Load Response System (eLRS) to serve as the interface for collecting and storing customer registration and settlement data. With the implementation of the LRS system, more detail is available on customer registrations and, as a result, there is an enhanced ability to capture multiple distinct locations aggregated to a single registration. The second column of Table 2-77 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

12 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 2-23 do not include these incentive payments.

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

	Credits			MWh Reductions		
	2010	2011	Percent Change	2010	2011	Percent Change
AECO	$25	$0	(100%)	0.2	0.0	(100%)
AEP	$0	$0	0%	0.0	0.0	0%
AP	$16,202	$6,020	(63%)	1,197.3	120.5	(90%)
BGE	$0	$0	0%	0.0	0.0	0%
ComEd	$10,986	$0	(100%)	370.2	0.0	(100%)
DAY	$0	$0	0%	0.0	0.0	0%
DLCO	$0	$44	0%	0.0	1.9	0%
Dominion	$213,189	$85,988	(60%)	3,779.3	817.8	(78%)
DPL	$0	$0	0%	0.0	0.0	0%
JCPL	$752	$0	(100%)	10.4	0.0	(100%)
Met-Ed	$16	$0	(100%)	1.5	0.0	(100%)
PECO	$70,000	$53,561	(23%)	2,372.9	1,203.5	(49%)
PENELEC	$156	$0	(100%)	1.1	0.0	(100%)
Pepco	$395	$0	(100%)	11.5	0.0	(100%)
PPL	$9,927	$0	(100%)	394.4	1.6	(100%)
PSEG	$0	$0	0%	0.0	0.0	0%
RECO	$0	$0	0%	0.0	0.0	0%
Total	$321,648	$145,613	(55%)	8,139	2,145.3	(74%)

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

Month	2008	2009	2010	2011
Jan	2,916	1,264	1,415	565
Feb	2,811	654	546	148
Mar	2,818	574	411	82
Apr	3,406	337	338	
May	3,336	918	673	
Jun	3,184	2,727	1,221	
Jul	3,339	2,879	3,007	
Aug	3,848	3,760	2,158	
Sep	3,264	2,570	660	
Oct	1,977	2,361	699	
Nov	1,105	2,321	672	
Dec	986	1,240	894	
Total	32,990	21,605	12,694	795

Table 2-80 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2010 and January through March 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		
May	12	233	9	201	6	140		
Jun	17	317	20	231	11	152		
Jul	16	295	21	183	18	243		
Aug	17	306	15	400	14	302		
Sep	17	312	11	181	11	97		
Oct	13	226	11	93	8	37		
Nov	14	208	9	143	7	40		
Dec	13	193	10	160	7	46		
Total Distinct Active	24	522	25	747	24	438	6	56

Table 2-81 Hourly frequency distribution of Economic Program MWh reductions and credits: January through March 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	0.26%	6	0.26%	$105	0.07%	$105	0.07%
2	6	0.30%	12	0.56%	$193	0.13%	$298	0.20%
3	12	0.57%	24	1.13%	$619	0.43%	$917	0.63%
4	4	0.19%	28	1.32%	$61	0.04%	$978	0.67%
5	8	0.38%	36	1.70%	$51	0.03%	$1,028	0.71%
6	35	1.62%	71	3.32%	$721	0.50%	$1,750	1.20%
7	332	15.47%	403	18.78%	$23,812	16.35%	$25,562	17.55%
8	503	23.44%	906	42.22%	$53,174	36.52%	$78,736	54.07%
9	280	13.07%	1,186	55.29%	$22,654	15.56%	$101,390	69.63%
10	169	7.86%	1,355	63.15%	$9,190	6.31%	$110,580	75.94%
11	121	5.65%	1,476	68.80%	$4,550	3.13%	$115,131	79.07%
12	97	4.52%	1,573	73.32%	$2,128	1.46%	$117,258	80.53%
13	64	3.00%	1,637	76.32%	$1,473	1.01%	$118,731	81.54%
14	26	1.22%	1,663	77.54%	$305	0.21%	$119,036	81.75%
15	38	1.79%	1,702	79.33%	$931	0.64%	$119,968	82.39%
16	52	2.40%	1,753	81.73%	$882	0.61%	$120,850	82.99%
17	109	5.07%	1,862	86.80%	$2,199	1.51%	$123,049	84.50%
18	104	4.84%	1,966	91.64%	$8,960	6.15%	$132,009	90.66%
19	112	5.21%	2,078	96.85%	$11,243	7.72%	$143,252	98.38%
20	20	0.92%	2,097	97.77%	$1,142	0.78%	$144,394	99.16%
21	17	0.80%	2,115	98.57%	$646	0.44%	$145,040	99.61%
22	15	0.70%	2,130	99.26%	$408	0.28%	$145,448	99.89%
23	11	0.49%	2,140	99.76%	$113	0.08%	$145,561	99.96%
24	5	0.24%	2,145	100.00%	$52	0.04%	$145,613	100.00%

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

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	6	0.28%	6	0.28%	$18	0.01%	$18	0.01%
$25 to $50	535	24.92%	541	25.20%	$8,211	5.64%	$8,229	5.65%
$50 to $75	506	23.57%	1,046	48.77%	$14,602	10.03%	$22,831	15.68%
$75 to $100	180	8.38%	1,226	57.15%	$9,976	6.85%	$32,807	22.53%
$100 to $125	40	1.87%	1,266	59.02%	$2,712	1.86%	$35,519	24.39%
$125 to $150	310	14.45%	1,576	73.48%	$27,162	18.65%	$62,680	43.05%
$150 to $200	327	15.24%	1,903	88.71%	$38,838	26.67%	$101,519	69.72%
$200 to $250	158	7.38%	2,061	96.09%	$27,623	18.97%	$129,142	88.69%
$250 to $300	64	2.99%	2,126	99.08%	$12,487	8.58%	$141,629	97.26%
> $300	20	0.92%	2,145	100.00%	$3,984	2.74%	$145,613	100.00%

Emergency Program

Load Management Program

Table 2-83 Zonal monthly capacity credits: January through March 2011 (See 2010 SOM, Table 2-85)

Zone	January	February	March	Total
AECO	$515,251	$465,388	$515,251	$1,495,889
AEP	$7,718,744	$6,971,769	$7,718,744	$22,409,257
APS	$4,272,819	$3,859,321	$4,272,819	$12,404,959
BGE	$5,039,828	$4,552,103	$5,039,828	$14,631,758
ComEd	$8,156,971	$7,367,587	$8,156,971	$23,681,529
DAY	$1,151,545	$1,040,105	$1,151,545	$3,343,196
DLCO	$1,118,544	$4,920,317	$1,118,544	$7,157,405
Dominion	$5,447,494	$982,920	$5,447,494	$11,877,908
DPL	$1,088,233	$1,010,298	$1,088,233	$3,186,764
JCPL	$1,301,034	$1,175,128	$1,301,034	$3,777,197
Met-Ed	$1,205,089	$1,088,468	$1,205,089	$3,498,646
PECO	$2,826,229	$2,552,723	$2,826,229	$8,205,180
PENELEC	$1,827,610	$1,650,744	$1,827,610	$5,305,963
Pepco	$1,307,359	$1,180,840	$1,307,359	$3,795,557
PPL	$4,115,164	$3,716,922	$4,115,164	$11,947,251
PSEG	$2,536,813	$2,291,315	$2,536,813	$7,364,941
RECO	$9,266	$8,369	$9,266	$26,902
Total	$49,637,993	$44,834,317	$49,637,993	$144,110,303