SECTION 2 – ENERGY MARKET, PART 1

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for January through June of 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 six 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 six months of 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1216 with a minimum of 889 and a maximum of 1564 in the January through June 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 6,212, or 4.0 percent, from 156,562 MW in the second quarter of 2010 to 162,774 MW in the second quarter of 2011. The large increase in offered supply is the result of the integration of the ATSI zone.

- The PJM system peak load for the second quarter of 2011 was 144,350 MW, which was 18,162 MW, or 14.4 percent, higher than the peak load in the second quarter of 2010. The peak load occurred on Wednesday, June 8, 2011, HE 17. The second quarter 2011 includes the integration of the ATSI transmission zone, which accounted for 12,707 MW in the peak hour of second quarter 2011. The peak load excluding the ATSI transmission zone was 131,699 MW, occurring on June 8, 2011, HE 18.

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.

- PJM average real-time load in the first six months of 2011 increased by 0.9 percent from the first six months of 2010, from 78,106 MW to 78,823 MW. PJM average day-ahead load in the first six months of 2011 decreased by 2.9 percent from the first six months of 2010, from 89,830 MW to 87,260 MW.

- PJM Real-Time Energy Market prices increased in the first six months of 2011 compared to the first six months of 2010. The load-weighted average LMP was 5.9 percent higher in the first six months of 2011 than in the first six months of 2010, $48.47 per MWh versus $45.75 per MWh.

- PJM Day-Ahead Energy Market prices increased in the first six months of 2011 compared to the first six months of 2010. The load-weighted LMP was 2.2 percent higher in the first six months of 2011 than in the first six months of 2010, $47.12 per MWh versus $46.12 per MWh.

- Levels of offer capping for local market power remained low. In the first six months of 2011, 0.7 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.

- The overcollected portion of transmission losses decreased in the first six months of 2011 to $308.4 million or 44.0 percent of the total losses compared to $377.5 million or 50.3 percent of total losses in the same period in 2010.

- In the first six months of 2011, the total MWh of load reduction under the Economic Program decreased by 16,377 MWh compared to the same period in 2010, from 20,225 MWh in 2010 to 3,848 MWh in 2011, an 81 percent decrease. Total payments under the Economic Program decreased by $476,431, from $761,854 in 2010 to $285,423 in 2010, a 63 percent decrease.

- In the first six 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 $61 million, or 29 percent, compared to the same period in 2010, from $215 Million in 2010 to $276 Million in 2011.

Recommendations

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

Overview

Market Structure

- **Supply.** During the second quarter of 2011, the PJM Energy Market received an hourly average of 162,774 MWh in day-ahead supply offers including hydroelectric generation, 6,212 MWh higher than the second quarter of 2010 average daily offered supply of 156,562 MWh.[4]

- **Demand.** The PJM system peak load for the second quarter of 2011 was 144,350 MW in the hour ended 1700 EPT on June 8, 2011, which was 18,162 MW, or 14.4 percent, higher than the PJM peak load for the second quarter of 2010, which was 126,189 MW in the hour ended 1700 EPT on June 23, 2010.[5] The peak load excluding the ATSI transmission zone was 131,699 MW, occurring on June 8, 2011 in the hour ended 1800 EPT.

- **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

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.

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).

pivotal supplier test (TPS)) as the trigger for offer capping in the first six 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 six months of 2011. In the Real-Time Energy Market offer-capped unit hours decreased from 1.2 percent in 2010 to 0.7 percent in the first six months of 2011.

- **Local Market Structure.** In the first six months of 2011, the AECO, AEP, AP, BGE, ComEd, Dominion, PECO, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the 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]

Market Performance: Load and Locational Marginal Price

- **Load.** On average, PJM real-time load increased in the first six months of 2011 by 0.9 percent from the first six months of 2010, from 78,106 MW to 78,823 MW. PJM day-ahead load decreased in the first six months of 2011 by 2.9 percent from the first six months of 2010, from 89,830 MW to 87,260 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 six months of 2011 compared to the first six months of 2010. The system simple average LMP was 5.2 percent higher in the first six months of 2011 than in the first six months of 2010, $45.51 per MWh versus $43.27 per MWh. The load-weighted LMP was 5.9 percent higher in the first six months of 2011 than in the first six months of 2010, $48.47 per MWh versus $45.75 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first six months of 2011 compared to the first six months of 2010. The system simple average LMP was 2.1 percent higher in the first six months of 2011 than in the first six months of 2010, $44.75 per MWh versus $43.81 per MWh. The load-weighted LMP was 2.2 percent higher in the first six months of 2011 than in the first six months of 2010, $47.12 per MWh versus $46.12 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 six months of 2011, 10.5 percent of real-time load was supplied by bilateral contracts, 27.1 percent by spot market purchases and 62.5 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased by 1.3 percentage points; reliance on spot supply increased by 6.9 percentage points; and reliance on self-supply decreased by 5.5 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.

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.

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

- **Demand-Side Response Activity.** In the first six months of 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 of factors, including lower price levels, lower load levels and improved measurement and verification. On the peak load day for the period January through June 2011 (June 8, 2011), there were 1,985.1 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 six months of 2011, Economic Program revenues decreased by $476,431 or 63 percent compared to the same period in 2010, from $761,854 to $285,423 while Load Management (LM) Program revenues increased by $61 million or 29 percent, from $215 million to $276 million. Through the first six months of 2011, Synchronized Reserve credits increased by $2.0 million compared to the same period in 2010, from $2.4 million in 2010 to $4.4 million in 2011.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first six 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 6,212 MWh in the second quarter of 2011 compared to the second quarter of 2010, while aggregate peak load increased by 18,162 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. In real-time market, average load in the first six months of 2011 increased from the same period in 2010, from 78,106 MW to 78,823 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 six 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.[7]

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

Market Structure

Supply

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

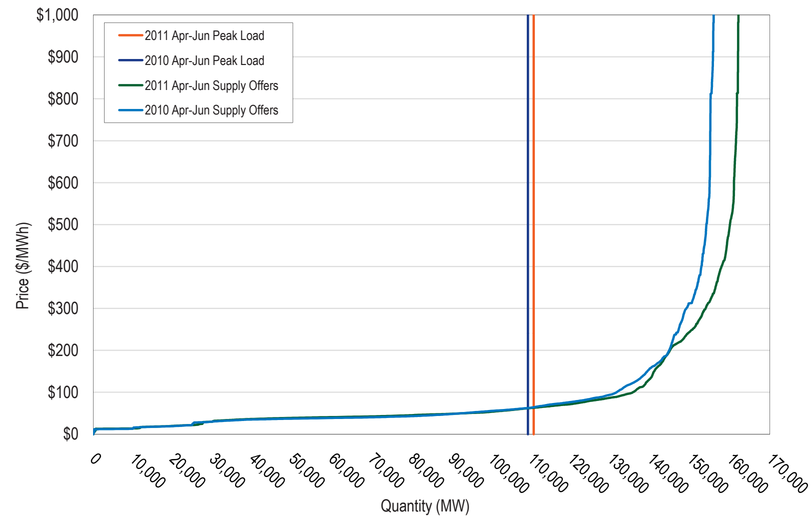


Table 2-2 Frequency distribution of unit offer prices: April through June 2011 (See 2010 SOM, Table 2-3)

Range	All Offers	PJM Dispatched Share of All Offers	Self-Scheduled Share of All Offers
($200) - $0	11.4%	26.2%	73.8%
$0 - $200	50.0%	89.0%	11.0%
$200 - $400	23.6%	95.0%	5.0%
$400 - $600	9.4%	98.9%	1.1%
$600 - $800	3.5%	97.4%	2.6%
$800 - $1,000	2.1%	84.5%	15.5%

7 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.

Demand

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

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2011	Wed, June 08	17	144,350	NA	NA
2010	Wed, June 23	17	126,188	(18,162)	(12.6%)
2009	Thu, June 25	17	116,751	(9,438)	(7.5%)
2008	Mon, June 09	17	130,100	13,349	11.4%
2007	Wed, June 27	16	130,971	871	0.7%
2006	Tue, May 30	17	121,165	(9,806)	(7.5%)
2005	Tue, June 28	16	124,052	2,887	2.4%
2004	Wed, June 09	17	77,676	(46,375)	(37.4%)
2003	Thu, June 26	17	61,310	(16,366)	(21.1%)
2002	Wed, June 26	15	60,176	(1,134)	(1.8%)

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

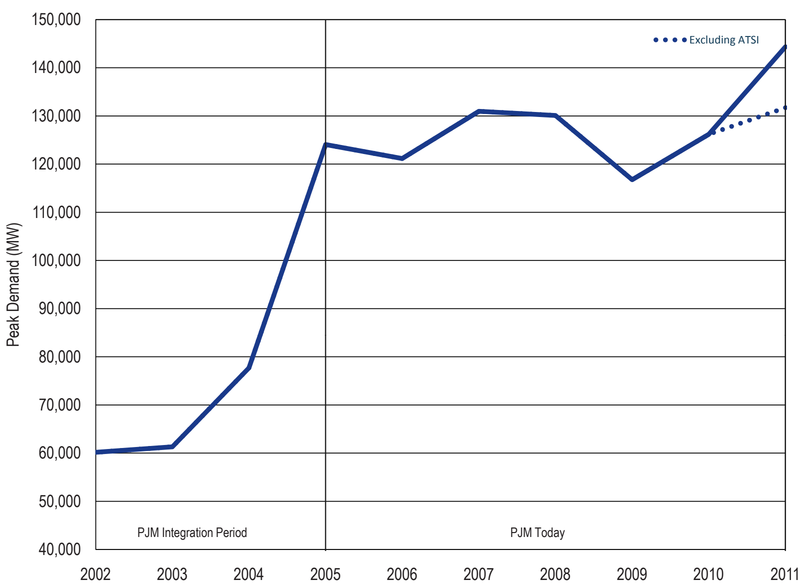
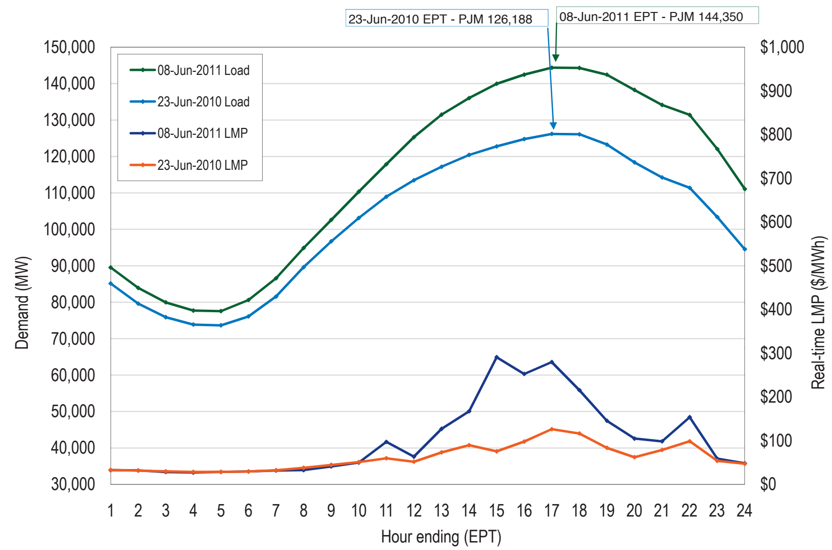


Figure 2-3 PJM second quarter peak-load comparison: Wednesday, June 8, 2011, and Wednesday, June 23, 2010 (See 2010 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

Table 2-4 PJM hourly Energy Market HHI: January through June 2011[8] (See 2010 SOM, Table 2-5)

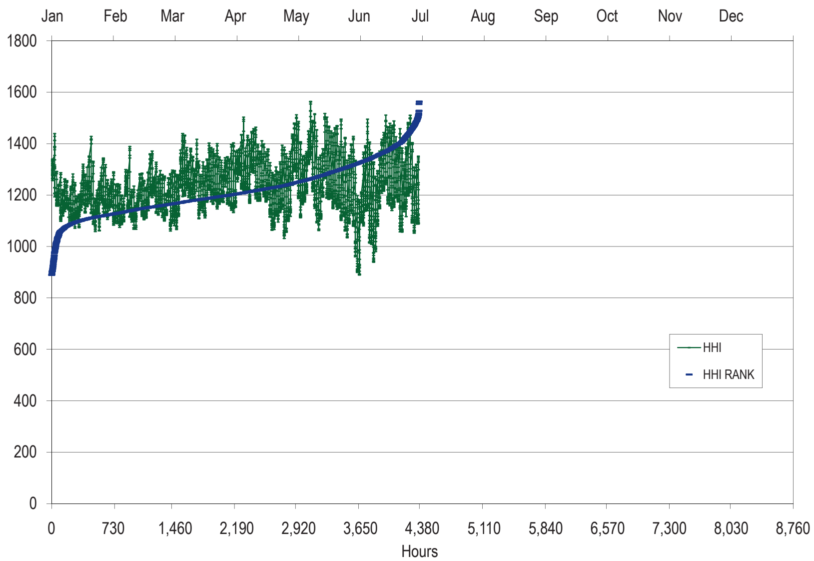
	Hourly Market HHI
Average	1216
Minimum	889
Maximum	1564
Highest market share (One hour)	30%
Highest market share (All hours)	20%
# Hours	4,343
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

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

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

	Minimum	Average	Maximum
Base	1058	1248	1546
Intermediate	765	2371	9809
Peak	649	6027	10000

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



Local Market Structure and Offer Capping

Table 2-6 Annual offer-capping statistics: Calendar years 2007 through June 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 - Jun)	0.7%	0.3%	0.0%	0.0%

Table 2-7 Real-time offer-capped unit statistics: January through June 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	11
80% and < 90%	0	0	1	0	1	17
75% and < 80%	0	0	0	0	0	7
70% and < 75%	0	0	0	0	0	6
60% and < 70%	0	0	0	0	0	20
50% and < 60%	0	0	0	0	0	22
25% and < 50%	1	1	0	0	2	87
10% and < 25%	1	2	1	1	0	36

Local Market Structure

Table 2-8 Three pivotal supplier results summary for regional constraints: January through June 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	4,912	851	17%	4,597	94%
	Off Peak	2,175	282	13%	2,054	94%
AEP-DOM	Peak	657	6	1%	657	100%
	Off Peak	1,914	32	2%	1,905	100%
AP South	Peak	13,172	194	1%	13,101	99%
	Off Peak	9,391	201	2%	9,325	99%
Bedington - Black Oak	Peak	4	0	0%	4	100%
	Off Peak	NA	NA	NA	NA	NA
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	160	87	54%	110	69%
	Off Peak	15	5	33%	14	93%

Table 2-9 Three pivotal supplier test details for regional constraints: January through June 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	304	1,781	15	2	13
	Off Peak	300	1,922	14	1	12
AEP-DOM	Peak	340	883	8	0	8
	Off Peak	367	1,298	8	0	8
AP South	Peak	403	1,089	8	0	8
	Off Peak	464	1,278	8	0	8
Bedington - Black Oak	Peak	64	536	10	0	10
	Off Peak	NA	NA	NA	NA	NA
Dominion East	Peak	115	184	1	0	1
	Off Peak	80	185	2	0	2
East	Peak	637	4,408	16	5	11
	Off Peak	327	3,323	12	5	7
West	Peak	483	3,615	15	7	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 June 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	4,912	191	4%	84	2%	44%
	Off Peak	2,175	81	4%	24	1%	30%
AEP-DOM	Peak	657	16	2%	10	2%	63%
	Off Peak	1,914	39	2%	24	1%	62%
AP South	Peak	13,172	126	1%	33	0%	26%
	Off Peak	9,391	166	2%	31	0%	19%
Bedington - Black Oak	Peak	4	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Dominion East	Peak	1,479	6	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	160	3	2%	0	0%	0%
	Off Peak	15	0	0%	0	0%	0%

Frequently Mitigated Unit and Associated Unit Adders

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

	FMUs and AUs			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any 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

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

Months Adder-Eligible	FMU & AU Count
1	3
2	2
3	2
4	1
5	17
6	123
Total	148

Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

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

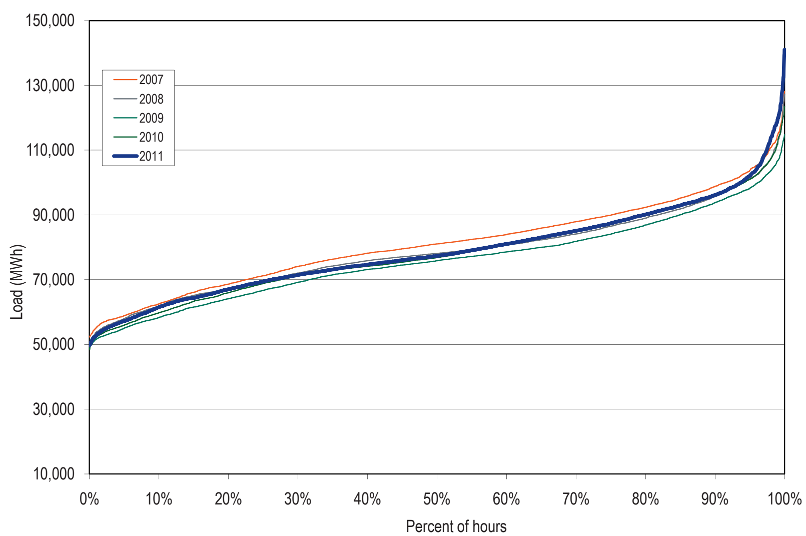
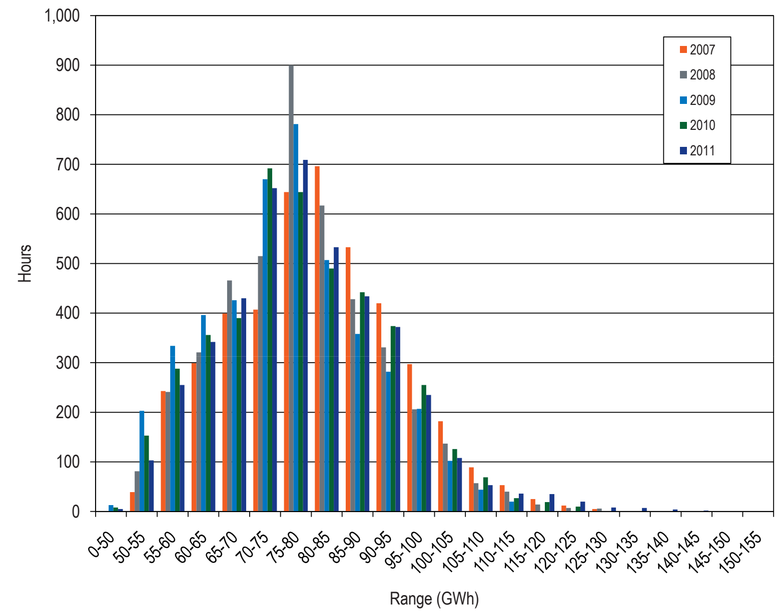


Figure 2-6 PJM real-time load histogram: January through June 2007 through 2011 (New Figure)



PJM Real-Time, Annual Average Load

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

	PJM Real-Time Load (MWh)			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	27,662	27,915	4,703	NA	NA	NA
1999	28,714	28,903	5,113	3.8%	3.5%	8.7%
2000	29,649	29,802	5,382	3.3%	3.1%	5.3%
2001	30,180	30,290	5,274	1.8%	1.6%	(2.0%)
2002	32,582	31,965	6,506	8.0%	5.5%	23.4%
2003	36,727	36,701	6,428	12.7%	14.8%	(1.2%)
2004	41,787	40,275	8,999	13.8%	9.7%	40.0%
2005	71,939	70,465	13,603	72.2%	75.0%	51.2%
2006	77,232	77,499	12,003	7.4%	10.0%	(11.8%)
2007	81,110	81,045	13,499	5.0%	4.6%	12.5%
2008	78,685	78,107	12,819	(3.0%)	(3.6%)	(5.0%)
2009	75,993	75,847	12,898	(3.4%)	(2.9%)	0.6%
2010	78,106	76,831	13,643	2.8%	1.3%	5.8%
2011	78,823	77,321	13,931	0.9%	0.6%	2.1%

PJM Real-Time, Monthly Average Load

Figure 2-7 PJM real-time average hourly load: Calendar years 2010 through June 2011 (See 2010 SOM, Figure 2-6)

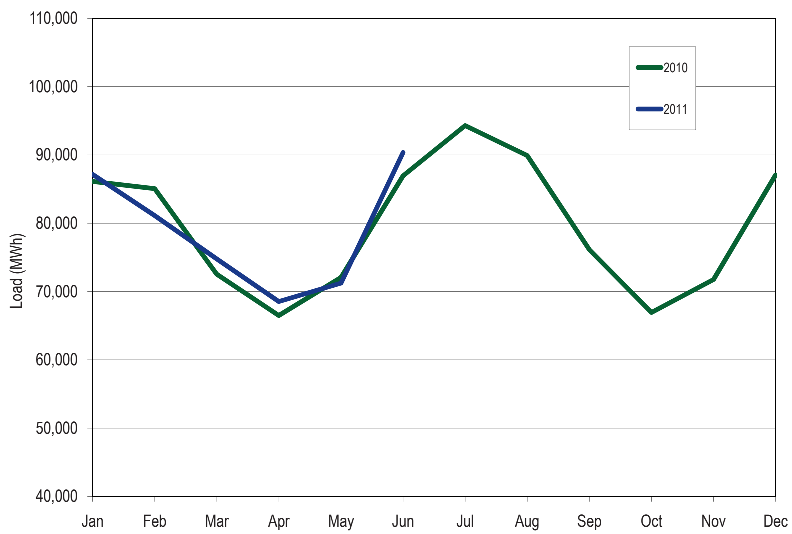


Table 2-14 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through June 2011 (See 2010 SOM, Table 2-30)

	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 (Jan - Jun)	74.63	25.20	53.84

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-8 PJM day-ahead load duration curves: January through June 2007 through 2011 (See 2010 SOM, Figure 2-7)

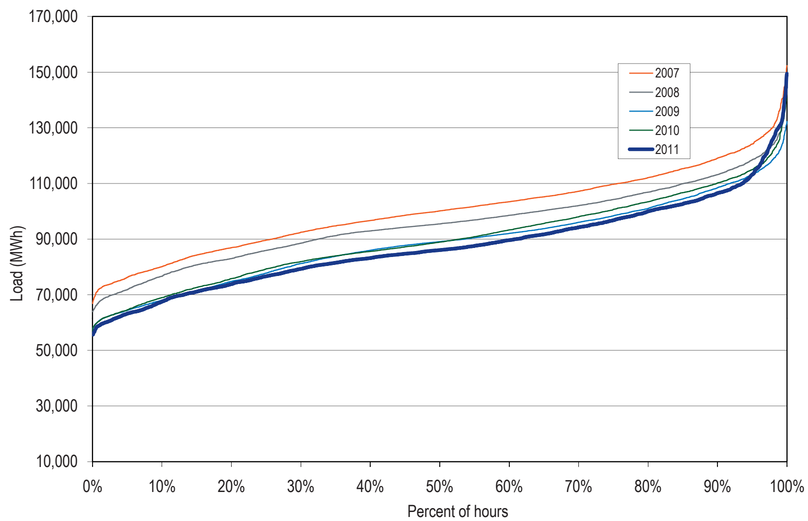
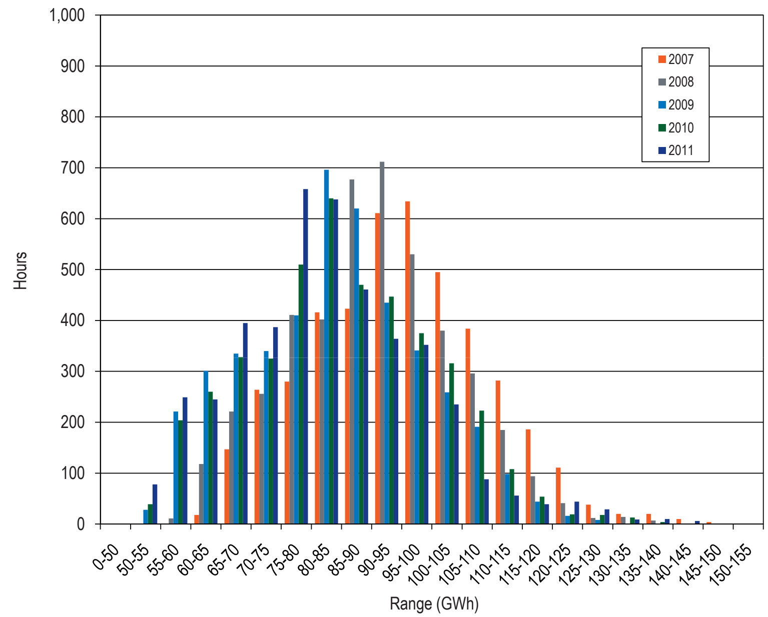


Figure 2-9 PJM day-ahead load histogram: January through June 2007 through 2011 (New Figure)



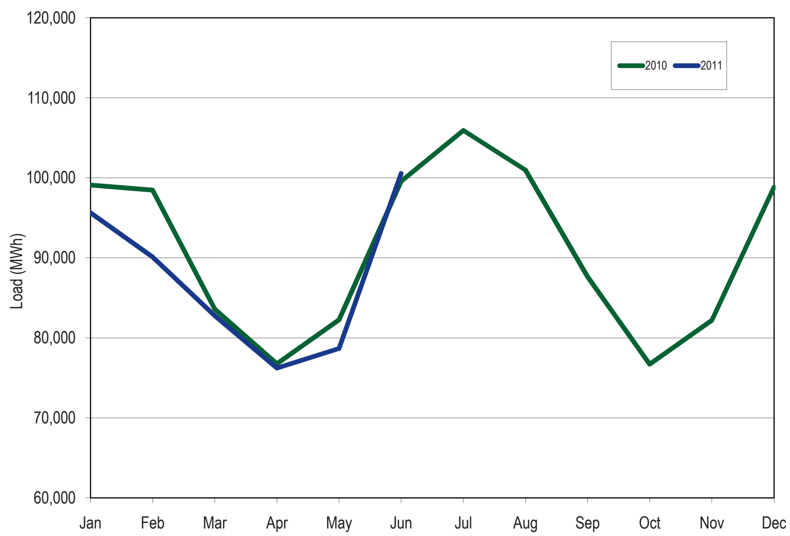
PJM Day-Ahead, Annual Average Load

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

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	35,448	36,822	8,138	NA	NA	NA
2001	32,443	31,916	5,938	(8.5%)	(13.3%)	(27.0%)
2002	37,497	36,362	8,268	15.6%	13.9%	39.2%
2003	44,112	44,378	7,730	17.6%	22.0%	(6.5%)
2004	49,393	47,476	10,003	12.0%	7.0%	29.4%
2005	85,784	84,465	14,632	73.7%	77.9%	46.3%
2006	91,060	90,850	12,862	6.1%	7.6%	(12.1%)
2007	100,097	100,118	14,532	9.9%	10.2%	13.0%
2008	95,486	95,444	13,724	(4.6%)	(4.7%)	(5.6%)
2009	88,688	89,066	14,650	(7.1%)	(6.7%)	6.7%
2010	89,830	88,894	15,372	1.3%	(0.2%)	4.9%
2011	87,260	86,041	15,402	(2.9%)	(3.2%)	0.2%

PJM Day-Ahead, Monthly Average Load

Figure 2-10 PJM day-ahead average load: Calendar years 2010 through June 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 June 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	75,532	816	10,913	87,260	78,823	8,437	(2,476)
Median	74,208	794	10,675	86,041	77,321	8,720	(1,955)
Standard deviation	13,371	186	2,349	15,402	13,931	1,471	(877)
Peak average	83,290	897	12,465	96,652	86,848	9,804	(2,661)
Peak median	80,961	879	12,204	94,080	84,494	9,585	(2,619)
Peak standard deviation	11,775	183	1,960	13,102	12,279	823	(1,137)
Off peak average	68,608	744	9,527	78,879	71,662	7,217	(2,310)
Off peak median	67,494	721	9,391	77,512	70,488	7,024	(2,367)
Off peak standard deviation	10,630	158	1,715	12,117	11,135	982	(733)

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

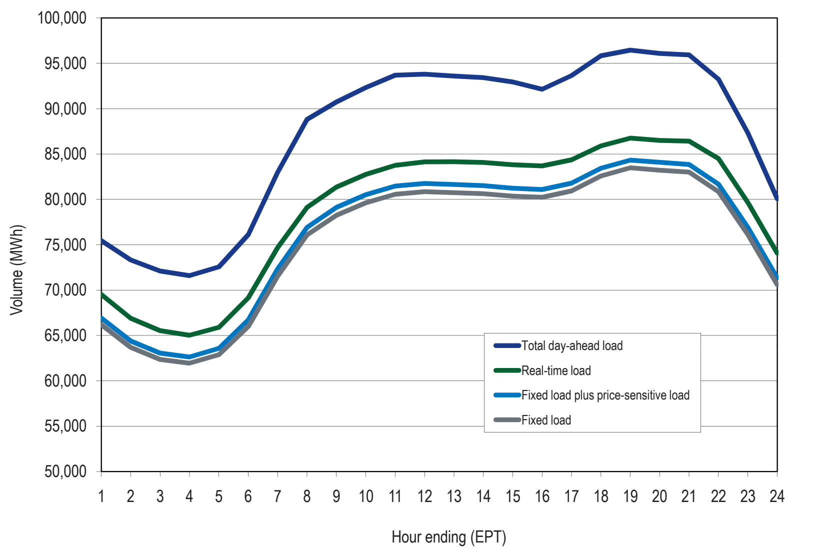
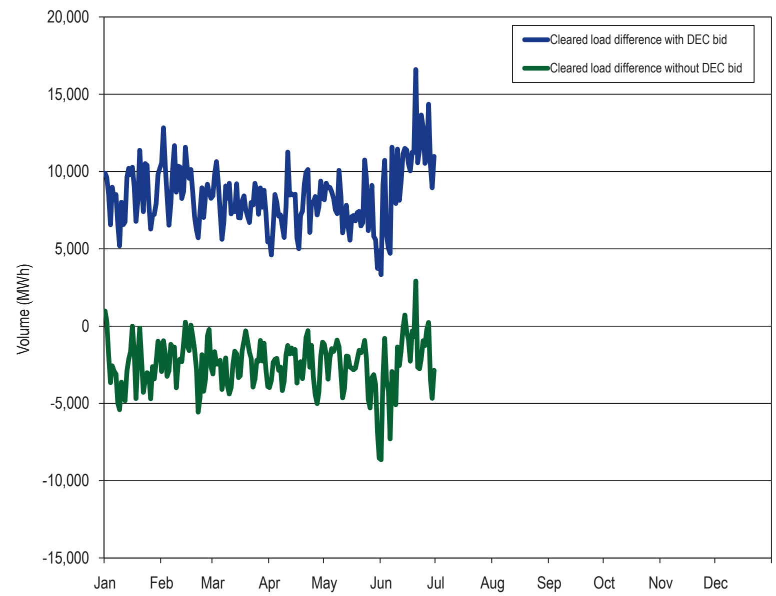


Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): January through June 2011 (See 2010 SOM, Figure 2-10)



Real-Time and Day-Ahead Generation

Table 2-17 Day-ahead and real-time generation (MWh): January through June 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	82,443	7,889	90,332	81,483	960	8,850
Median	81,194	7,802	89,064	80,089	1,105	8,976
Standard deviation	14,810	1,266	15,618	13,677	1,133	1,941
Peak average	91,256	8,676	99,932	89,371	1,885	10,561
Peak median	88,985	8,570	97,584	87,052	1,933	10,532
Peak standard deviation	12,599	1,064	13,162	12,011	588	1,151
Off peak average	74,578	7,188	81,766	74,443	135	7,322
Off peak median	73,386	7,079	80,500	73,368	18	7,133
Off peak standard deviation	11,929	990	12,305	10,964	964	1,341

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

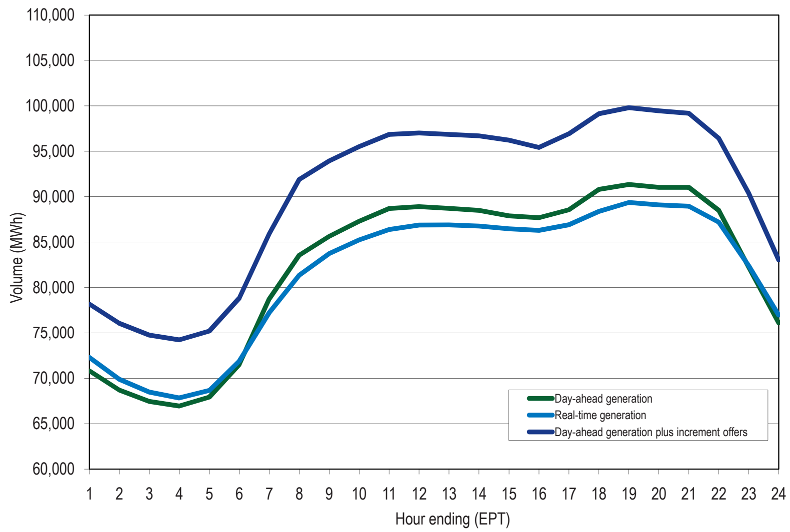
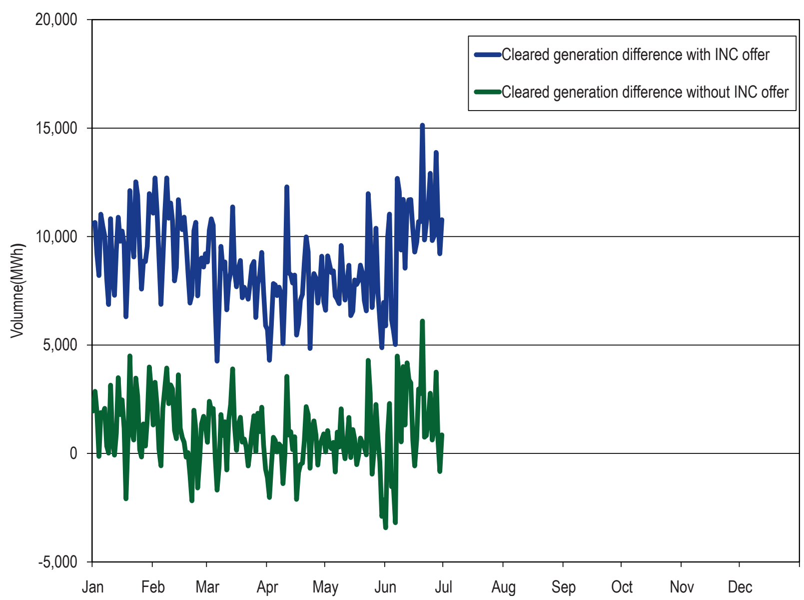


Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January through June 2011 (See 2010 SOM, Figure 2-12)



Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-15 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: January through June 2007 through 2011 (See 2010 SOM, Figure 2-13)

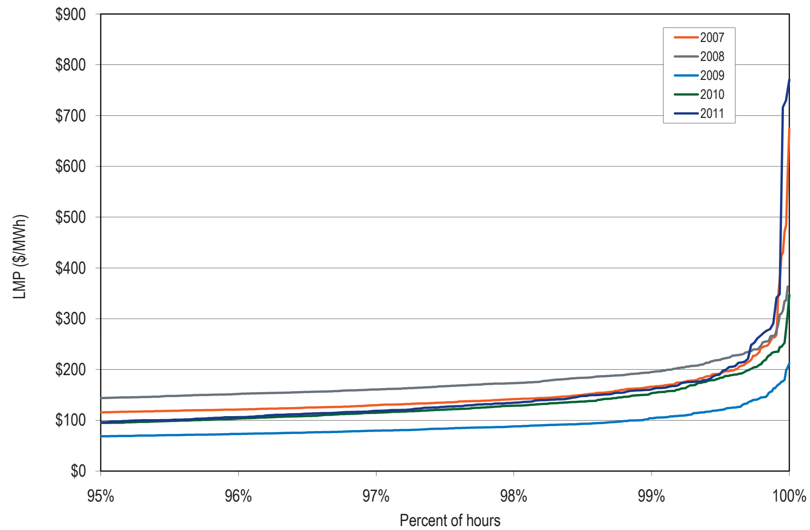
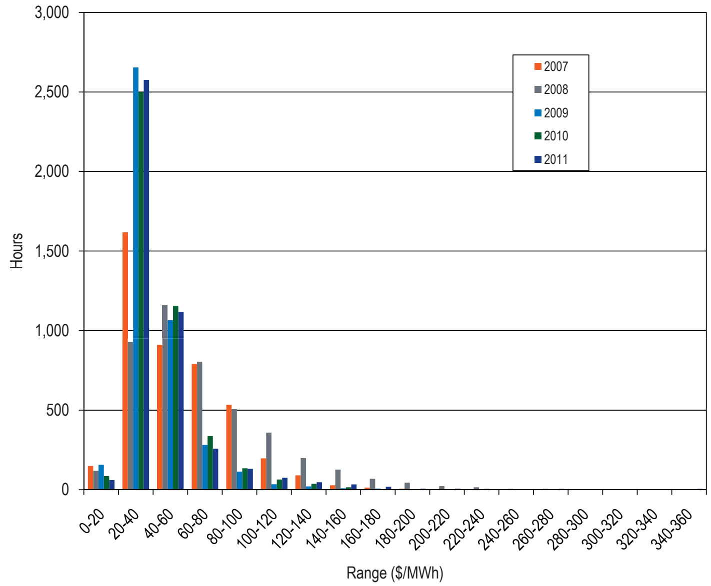


Figure 2-16 Price histogram for the PJM Real-Time Energy Market: January through June 2007 through 2011 (New Figure)



PJM Real-Time, Annual Average LMP

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

	Real-Time LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%

Zonal Real-Time, Annual Average LMP

Table 2-19 Zonal real-time, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-35)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AECO	$47.67	$51.33	$3.66	7.7%
AEP	$37.85	$40.15	$2.30	6.1%
AP	$42.65	$45.27	$2.63	6.2%
ATSI	NA	$41.94	NA	NA
BGE	$50.08	$52.07	$1.98	4.0%
ComEd	$33.60	$34.75	$1.15	3.4%
DAY	$37.68	$40.27	$2.59	6.9%
DLCO	$37.71	$39.79	$2.08	5.5%
Dominion	$49.34	$50.17	$0.83	1.7%
DPL	$48.14	$50.93	$2.78	5.8%
JCPL	$47.26	$51.39	$4.13	8.7%
Met-Ed	$46.36	$49.28	$2.93	6.3%
PECO	$46.72	$50.17	$3.46	7.4%
PENELEC	$40.77	$45.14	$4.37	10.7%
Pepco	$50.15	$51.34	$1.19	2.4%
PPL	$45.44	$50.00	$4.56	10.0%
PSEG	$48.45	$52.19	$3.74	7.7%
RECO	$46.44	$45.74	($0.70)	(1.5%)
PJM	$43.27	$45.51	$2.24	5.2%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-20 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-36)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
Delaware	$47.44	$50.27	$2.83	6.0%
Illinois	$33.60	$34.75	$1.15	3.4%
Indiana	$36.87	$39.22	$2.35	6.4%
Kentucky	$38.34	$39.59	$1.25	3.2%
Maryland	$49.92	$51.40	$1.48	3.0%
Michigan	$37.45	$39.87	$2.42	6.5%
New Jersey	$47.97	$51.74	$3.76	7.8%
North Carolina	$47.56	$48.50	$0.94	2.0%
Ohio	$37.08	$40.31	$3.23	8.7%
Pennsylvania	$44.00	$47.59	$3.60	8.2%
Tennessee	$39.38	$39.61	$0.23	0.6%
Virginia	$48.08	$48.76	$0.68	1.4%
West Virginia	$38.13	$41.31	$3.18	8.3%
District of Columbia	$50.37	$51.40	$1.03	2.0%

Hub Real-Time, Annual Average LMP

Table 2-21 Hub real-time, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-37)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AEP Gen Hub	$35.37	$38.06	$2.69	7.6%
AEP-DAY Hub	$37.12	$39.49	$2.37	6.4%
ATSI Gen Hub	NA	$41.19	$41.19	NA
Chicago Gen Hub	$32.79	$33.70	$0.90	2.8%
Chicago Hub	$33.77	$34.91	$1.13	3.4%
Dominion Hub	$48.01	$49.65	$1.64	3.4%
Eastern Hub	$48.15	$51.20	$3.06	6.4%
N Illinois Hub	$33.40	$34.52	$1.12	3.4%
New Jersey Hub	$47.86	$51.80	$3.93	8.2%
Ohio Hub	$37.16	$39.48	$2.32	6.2%
West Interface Hub	$40.10	$42.29	$2.19	5.5%
Western Hub	$43.87	$46.55	$2.68	6.1%

Real-Time, Load-Weighted, Average LMP

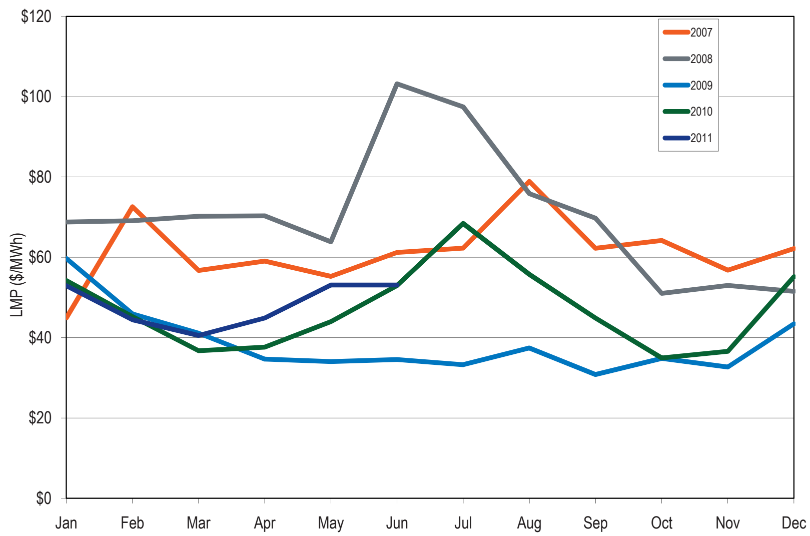
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-22 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 1998 through 2011 (See 2010 SOM, Table 2-38)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%

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

Figure 2-17 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through June 2011 (See 2010 SOM, Figure 2-14)



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

Table 2-23 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-39)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AECO	$51.21	$55.67	$4.47	8.7%
AEP	$39.53	$41.82	$2.29	5.8%
AP	$44.66	$47.69	$3.03	6.8%
ATSI	NA	$45.95	NA	NA
BGE	$53.92	$57.18	$3.26	6.1%
ComEd	$35.48	$36.75	$1.27	3.6%
DAY	$39.50	$42.49	$2.98	7.6%
DLCO	$39.37	$41.75	$2.38	6.1%
Dominion	$53.75	$54.64	$0.89	1.7%
DPL	$51.66	$55.43	$3.77	7.3%
JCPL	$50.97	$56.21	$5.25	10.3%
Met-Ed	$49.02	$52.81	$3.79	7.7%
PECO	$49.58	$54.04	$4.46	9.0%
PENELEC	$42.12	$47.07	$4.95	11.8%
Pepco	$54.16	$56.39	$2.23	4.1%
PPL	$47.93	$53.42	$5.48	11.4%
PSEG	$51.48	$56.10	$4.62	9.0%
RECO	$50.02	$50.25	$0.24	0.5%
PJM	$45.75	$48.47	$2.72	5.9%

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

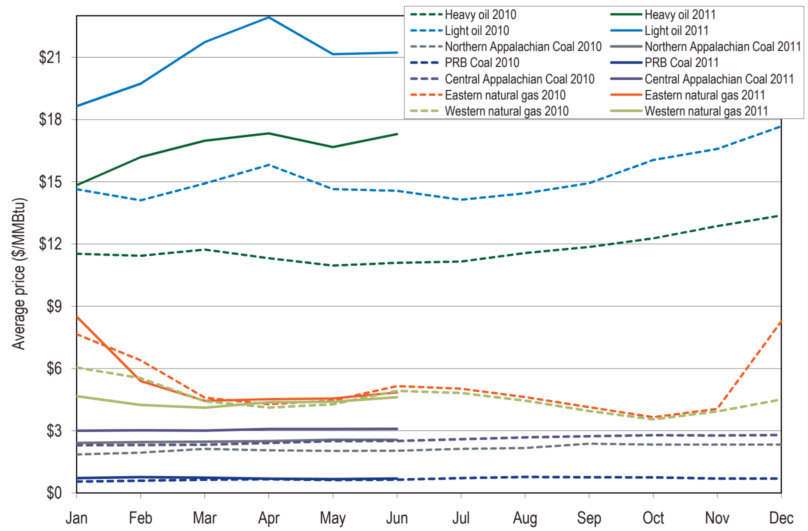
Table 2-24 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-40)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
Delaware	$50.56	$54.46	$3.90	7.7%
Illinois	$35.48	$36.75	$1.27	3.6%
Indiana	$38.03	$40.59	$2.56	6.7%
Kentucky	$40.64	$41.61	$0.97	2.4%
Maryland	$53.98	$56.41	$2.43	4.5%
Michigan	$39.05	$41.68	$2.63	6.7%
New Jersey	$51.27	$55.94	$4.68	9.1%
North Carolina	$52.03	$52.32	$0.29	0.6%
Ohio	$38.55	$42.46	$3.90	10.1%
Pennsylvania	$46.17	$50.57	$4.40	9.5%
Tennessee	$42.26	$41.71	($0.54)	(1.3%)
Virginia	$52.18	$52.85	$0.67	1.3%
West Virginia	$39.88	$43.03	$3.15	7.9%
District of Columbia	$53.53	$55.45	$1.92	3.6%

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

Fuel Cost

Figure 2-18 Spot average fuel price comparison: Calendar years 2010 through June 2011 (See 2010 SOM, Table 2-15)



Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-19 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: January through June 2007 through 2011 (See 2010 SOM, Figure 2-16)

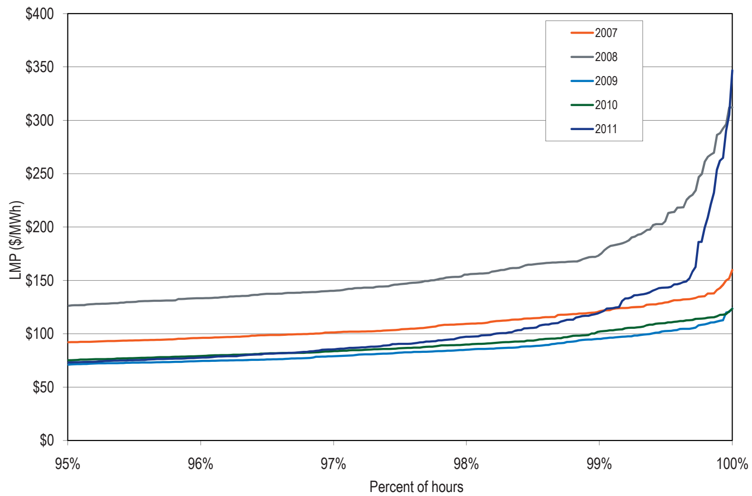
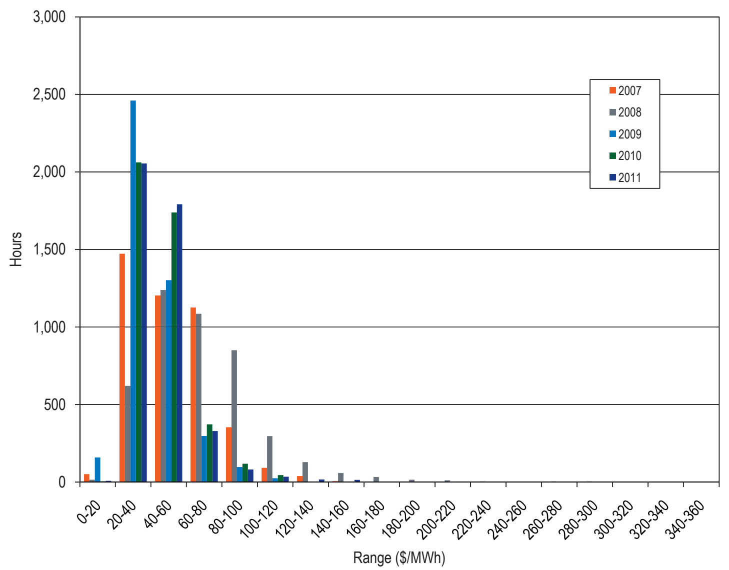


Figure 2-20 Price histogram for the PJM Day-Ahead Energy Market: January through June 2007 through 2011 (New Figure)



PJM Day-Ahead, Annual Average LMP

Table 2-25 PJM day-ahead, simple average LMP (Dollars per MWh): January through June 2000 through 2011 (See 2010 SOM, Table 2-43)

	Day-Ahead LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$30.29	$22.72	$19.75	NA	NA	NA
2001	$35.02	$31.34	$17.43	15.6%	38.0%	(11.8%)
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%

Zonal Day-Ahead, Annual Average LMP

Table 2-26 Zonal day-ahead, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-44)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AECO	$48.54	$51.31	$2.77	5.7%
AEP	$38.07	$40.00	$1.92	5.1%
AP	$43.14	$44.98	$1.84	4.3%
ATSI	NA	$43.16	NA	NA
BGE	$51.38	$51.15	($0.23)	(0.4%)
ComEd	$34.01	$34.53	$0.52	1.5%
DAY	$37.60	$39.80	$2.20	5.8%
DLCO	$38.37	$38.94	$0.58	1.5%
Dominion	$50.36	$49.10	($1.26)	(2.5%)
DPL	$48.70	$51.23	$2.52	5.2%
JCPL	$48.27	$51.22	$2.95	6.1%
Met-Ed	$47.38	$49.02	$1.63	3.4%
PECO	$47.81	$50.58	$2.76	5.8%
PENELEC	$42.38	$44.68	$2.31	5.4%
Pepco	$51.71	$50.96	($0.75)	(1.4%)
PPL	$46.45	$49.57	$3.13	6.7%
PSEG	$49.27	$52.16	$2.90	5.9%
RECO	$48.07	$48.48	$0.41	0.9%
PJM	$43.81	$44.75	$0.94	2.1%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-27 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-45)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
Delaware	$48.02	$50.42	$2.40	5.0%
Illinois	$34.01	$34.53	$0.52	1.5%
Indiana	$37.01	$39.04	$2.02	5.5%
Kentucky	$38.31	$39.41	$1.10	2.9%
Maryland	$51.14	$50.75	($0.40)	(0.8%)
Michigan	$37.51	$39.79	$2.28	6.1%
New Jersey	$48.88	$51.72	$2.85	5.8%
North Carolina	$48.75	$47.57	($1.18)	(2.4%)
Ohio	$37.05	$39.73	$2.68	7.2%
Pennsylvania	$44.97	$47.40	$2.42	5.4%
Tennessee	$39.64	$39.91	$0.27	0.7%
Virginia	$49.21	$48.07	($1.14)	(2.3%)
West Virginia	$38.47	$41.45	$2.97	7.7%
District of Columbia	$51.92	$50.94	($0.98)	(1.9%)

Day-Ahead, Load-Weighted, Average LMP

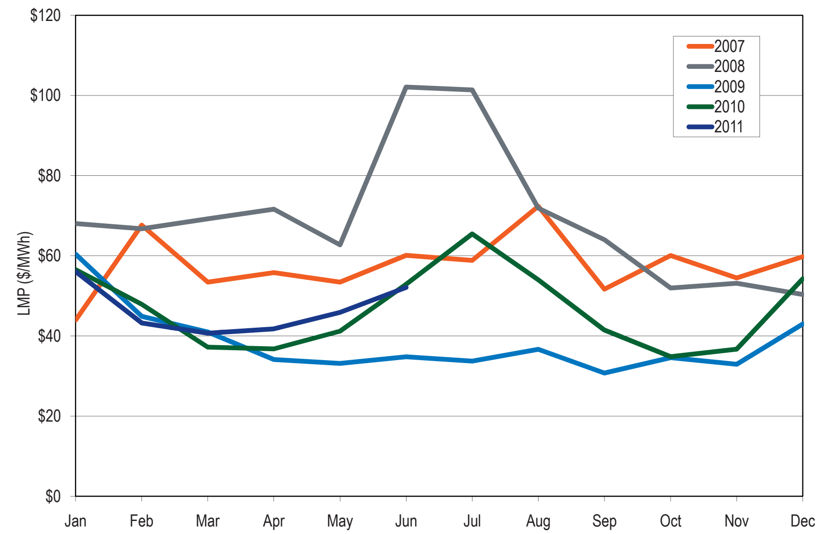
PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-28 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2000 through 2011 (See 2010 SOM, Table 2-46)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Jan - Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$34.12	$30.00	$20.13	NA	NA	NA
2001	$37.08	$33.91	$18.11	8.7%	13.0%	(10.0%)
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.8%	82.6%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%

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

Figure 2-21 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2007 through June 2011 (See 2010 SOM, Table 2-17)



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-29 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-47)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
AECO	$52.63	$55.19	$2.56	4.9%
AEP	$39.68	$41.40	$1.72	4.3%
AP	$45.14	$46.81	$1.67	3.7%
ATSI	NA	$46.35	NA	NA
BGE	$55.13	$55.10	($0.03)	(0.1%)
ComEd	$35.49	$35.89	$0.39	1.1%
DAY	$39.30	$41.46	$2.16	5.5%
DLCO	$40.16	$40.51	$0.35	0.9%
Dominion	$54.80	$52.73	($2.07)	(3.8%)
DPL	$52.03	$55.24	$3.21	6.2%
JCPL	$51.29	$54.69	$3.40	6.6%
Met-Ed	$49.92	$51.54	$1.63	3.3%
PECO	$50.48	$53.90	$3.42	6.8%
PENELEC	$43.66	$46.55	$2.89	6.6%
Pepco	$54.53	$54.75	$0.22	0.4%
PPL	$48.88	$52.43	$3.55	7.3%
PSEG	$51.91	$55.30	$3.40	6.5%
RECO	$51.58	$51.84	$0.26	0.5%
PJM	$46.12	$47.12	$1.00	2.2%

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

Table 2-30 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-48)

	2010 (Jan - Jun)	2011 (Jan - Jun)	Difference	Difference as Percent of 2010
Delaware	$51.06	$54.08	$3.02	5.9%
Illinois	$35.49	$35.89	$0.39	1.1%
Indiana	$38.35	$40.35	$2.00	5.2%
Kentucky	$40.18	$40.95	$0.78	1.9%
Maryland	$54.56	$54.47	($0.09)	(0.2%)
Michigan	$38.81	$41.11	$2.29	5.9%
New Jersey	$51.80	$55.02	$3.22	6.2%
North Carolina	$52.99	$51.27	($1.72)	(3.2%)
Ohio	$38.47	$41.86	$3.39	8.8%
Pennsylvania	$46.95	$49.85	$2.90	6.2%
Tennessee	$42.08	$41.71	($0.37)	(0.9%)
Virginia	$53.26	$51.35	($1.90)	(3.6%)
West Virginia	$40.20	$42.89	$2.69	6.7%
District of Columbia	$54.37	$54.29	($0.08)	(0.1%)

Marginal Losses

Table 2-31 PJM real-time, simple average LMP components (Dollars per MWh): January through June 2008 to 2011 (See 2010 SOM, Table 2-50)[9]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008 (Jan - Jun)	$70.19	$70.09	$0.06	$0.04
2009 (Jan - Jun)	$40.12	$40.04	$0.05	$0.03
2010 (Jan - Jun)	$43.27	$43.18	$0.05	$0.04
2011 (Jan - Jun)	$45.51	$45.45	$0.04	$0.03

9 The years 2006 and 2007 were removed from Table 2-31 and Table 2-35 because PJM did not begin to include marginal losses in economic dispatch and LMP models until June 1, 2007.

Table 2-32 Zonal real-time, simple average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-51)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$47.67	$43.18	$2.24	$2.25	$51.33	$45.45	$3.70	$2.18
AEP	$37.85	$43.18	($3.81)	($1.52)	$40.15	$45.45	($3.76)	($1.54)
AP	$42.65	$43.18	($0.37)	($0.17)	$45.27	$45.45	($0.18)	$0.01
ATSI	NA	NA	NA	NA	$41.94	$47.74	($5.05)	($0.76)
BGE	$50.08	$43.18	$4.72	$2.18	$52.07	$45.45	$4.62	$2.00
ComEd	$33.60	$43.18	($6.74)	($2.84)	$34.75	$45.45	($7.78)	($2.91)
DAY	$37.68	$43.18	($4.52)	($0.98)	$40.27	$45.45	($4.18)	($1.00)
DLCO	$37.71	$43.18	($3.88)	($1.59)	$39.79	$45.45	($4.41)	($1.25)
Dominion	$49.34	$43.18	$5.35	$0.81	$50.17	$45.45	$4.01	$0.72
DPL	$48.14	$43.18	$2.52	$2.44	$50.93	$45.45	$2.99	$2.49
JCPL	$47.26	$43.18	$1.79	$2.29	$51.39	$45.45	$3.62	$2.33
Met-Ed	$46.36	$43.18	$2.04	$1.13	$49.28	$45.45	$2.90	$0.94
PECO	$46.72	$43.18	$1.92	$1.61	$50.17	$45.45	$3.07	$1.65
PENELEC	$40.77	$43.18	($2.13)	($0.29)	$45.14	$45.45	($0.74)	$0.43
Pepco	$50.15	$43.18	$5.57	$1.41	$51.34	$45.45	$4.66	$1.23
PPL	$45.44	$43.18	$1.36	$0.90	$50.00	$45.45	$3.52	$1.03
PSEG	$48.45	$43.18	$2.96	$2.31	$52.19	$45.45	$4.43	$2.32
RECO	$46.44	$43.18	$1.25	$2.00	$45.74	$45.45	($1.79)	$2.08

Table 2-33 Hub real-time, simple average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-52)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.37	$43.18	($4.86)	($2.95)	$38.06	$45.45	($4.44)	($2.94)
AEP-DAY Hub	$37.12	$43.18	($4.34)	($1.73)	$39.49	$45.45	($4.18)	($1.78)
ATSI Gen Hub	NA	NA	NA	NA	$41.19	$47.68	($5.33)	($1.17)
Chicago Gen Hub	$32.79	$43.18	($7.00)	($3.38)	$33.70	$45.45	($8.25)	($3.50)
Chicago Hub	$33.77	$43.18	($6.59)	($2.82)	$34.91	$45.45	($7.66)	($2.88)
Dominion Hub	$48.01	$43.18	$4.52	$0.30	$49.65	$45.45	$3.90	$0.30
Eastern Hub	$48.15	$43.18	$2.35	$2.62	$51.20	$45.45	$3.05	$2.71
N Illinois Hub	$33.40	$43.18	($6.73)	($3.05)	$34.52	$45.45	($7.79)	($3.13)
New Jersey Hub	$47.86	$43.18	$2.43	$2.25	$51.80	$45.45	$4.08	$2.27
Ohio Hub	$37.16	$43.18	($4.34)	($1.68)	$39.48	$45.45	($4.24)	($1.73)
West Interface Hub	$40.10	$43.18	($1.68)	($1.40)	$42.29	$45.45	($1.99)	($1.17)
Western Hub	$43.87	$43.18	$0.93	($0.25)	$46.55	$45.45	$1.13	($0.03)

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

Table 2-34 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-53)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$51.21	$46.08	$2.71	$2.42	$55.67	$48.74	$4.51	$2.42
AEP	$39.53	$45.29	($4.18)	($1.59)	$41.82	$47.80	($4.35)	($1.64)
AP	$44.66	$45.45	($0.60)	($0.19)	$47.69	$48.10	($0.40)	($0.01)
ATSI	NA	NA	NA	NA	$45.95	$52.72	($6.01)	($0.75)
BGE	$53.92	$46.03	$5.54	$2.35	$57.18	$48.91	$6.06	$2.20
ComEd	$35.48	$45.16	($6.79)	($2.89)	$36.75	$47.87	($8.10)	($3.02)
DAY	$39.50	$45.49	($5.02)	($0.97)	$42.49	$48.35	($4.84)	($1.03)
DLCO	$39.37	$45.19	($4.13)	($1.69)	$41.75	$48.21	($5.10)	($1.35)
Dominion	$53.75	$46.37	$6.49	$0.89	$54.64	$48.94	$4.93	$0.77
DPL	$51.66	$46.29	$2.71	$2.66	$55.43	$48.90	$3.74	$2.80
JCPL	$50.97	$46.35	$2.16	$2.45	$56.21	$49.21	$4.43	$2.57
Met-Ed	$49.02	$45.56	$2.27	$1.19	$52.81	$48.29	$3.46	$1.05
PECO	$49.58	$45.71	$2.18	$1.69	$54.04	$48.52	$3.71	$1.81
PENELEC	$42.12	$44.90	($2.45)	($0.33)	$47.07	$47.49	($0.86)	$0.45
Pepco	$54.16	$46.11	$6.55	$1.50	$56.39	$48.96	$6.09	$1.33
PPL	$47.93	$45.52	$1.48	$0.94	$53.42	$48.09	$4.18	$1.14
PSEG	$51.48	$45.73	$3.33	$2.42	$56.10	$48.58	$5.01	$2.51
RECO	$50.02	$46.27	$1.62	$2.13	$50.25	$49.48	($1.51)	$2.28
PJM	$45.75	$45.65	$0.06	$0.04	$48.47	$48.40	$0.05	$0.03

Table 2-35 PJM day-ahead, simple average LMP components (Dollars per MWh): January through June 2008 to 2011 (See 2010 SOM, Table 2-54)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008 (Jan - Jun)	$70.12	$70.51	($0.17)	($0.23)
2009 (Jan - Jun)	$40.01	$40.27	($0.14)	($0.12)
2010 (Jan - Jun)	$43.81	$43.74	$0.07	$0.00
2011 (Jan - Jun)	$44.75	$44.94	($0.09)	($0.10)

Table 2-36 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-55)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$48.54	$43.74	$2.14	$2.66	$51.31	$44.94	$3.72	$2.65
AEP	$38.07	$43.74	($3.52)	($2.16)	$40.00	$44.94	($3.23)	($1.72)
AP	$43.14	$43.74	($0.45)	($0.16)	$44.98	$44.94	$0.02	$0.01
ATSI	NA	NA	NA	NA	$43.16	$48.03	($3.93)	($0.94)
BGE	$51.38	$43.74	$4.75	$2.89	$51.15	$44.94	$4.05	$2.16
ComEd	$34.01	$43.74	($5.95)	($3.78)	$34.53	$44.94	($7.01)	($3.41)
DAY	$37.60	$43.74	($4.25)	($1.89)	$39.80	$44.94	($4.00)	($1.14)
DLCO	$38.37	$43.74	($3.47)	($1.91)	$38.94	$44.94	($4.68)	($1.33)
Dominion	$50.36	$43.74	$5.20	$1.42	$49.10	$44.94	$3.52	$0.64
DPL	$48.70	$43.74	$2.26	$2.70	$51.23	$44.94	$3.28	$3.00
JCPL	$48.27	$43.74	$1.56	$2.97	$51.22	$44.94	$3.42	$2.85
Met-Ed	$47.38	$43.74	$2.22	$1.42	$49.02	$44.94	$3.06	$1.02
PECO	$47.81	$43.74	$1.87	$2.20	$50.58	$44.94	$3.49	$2.14
PENELEC	$42.38	$43.74	($1.50)	$0.14	$44.68	$44.94	($0.57)	$0.31
Pepco	$51.71	$43.74	$5.75	$2.21	$50.96	$44.94	$4.49	$1.52
PPL	$46.45	$43.74	$1.58	$1.12	$49.57	$44.94	$3.57	$1.07
PSEG	$49.27	$43.74	$2.34	$3.18	$52.16	$44.94	$4.26	$2.96
RECO	$48.07	$43.74	$1.52	$2.80	$48.48	$44.94	$1.22	$2.31

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

Table 2-37 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through June 2010 and 2011 (See 2010 SOM, Table 2-56)

	2010 (Jan - Jun)				2011 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$52.63	$47.19	$2.46	$2.97	$55.19	$47.79	$4.47	$2.92
AEP	$39.68	$45.85	($3.91)	($2.26)	$41.40	$46.99	($3.76)	($1.83)
AP	$45.14	$45.99	($0.67)	($0.18)	$46.81	$47.02	($0.20)	($0.01)
ATSI	NA	NA	NA	NA	$46.35	$51.93	($4.59)	($0.99)
BGE	$55.13	$46.52	$5.49	$3.12	$55.10	$47.78	$4.96	$2.36
ComEd	$35.49	$45.44	($6.06)	($3.88)	$35.89	$46.72	($7.29)	($3.54)
DAY	$39.30	$46.01	($4.75)	($1.95)	$41.46	$47.33	($4.68)	($1.19)
DLCO	$40.16	$45.78	($3.61)	($2.01)	$40.51	$47.17	($5.25)	($1.41)
Dominion	$54.80	$46.85	$6.41	$1.54	$52.73	$47.93	$4.17	$0.63
DPL	$52.03	$46.72	$2.41	$2.90	$55.24	$47.91	$4.01	$3.32
JCPL	$51.29	$46.46	$1.67	$3.16	$54.69	$47.74	$3.89	$3.07
Met-Ed	$49.92	$46.02	$2.42	$1.49	$51.54	$47.00	$3.44	$1.11
PECO	$50.48	$46.18	$1.99	$2.32	$53.90	$47.41	$4.16	$2.33
PENELEC	$43.66	$45.25	($1.70)	$0.11	$46.55	$46.96	($0.74)	$0.33
Pepco	$54.53	$45.82	$6.37	$2.33	$54.75	$47.61	$5.50	$1.64
PPL	$48.88	$46.01	$1.68	$1.18	$52.43	$47.19	$4.08	$1.16
PSEG	$51.91	$46.09	$2.48	$3.34	$55.30	$47.54	$4.62	$3.14
RECO	$51.58	$46.90	$1.67	$3.01	$51.84	$47.89	$1.53	$2.42
PJM	$46.12	$46.04	$0.08	($0.00)	$47.12	$47.32	($0.10)	($0.11)

Marginal Loss Costs and Loss Credits

Table 2-38 Marginal loss costs and loss credits: January through June 2008 to 2011 (See 2010 SOM, Table 2-57)

	Total Marginal Loss Costs	Loss Credits	Percent
2008 (Jan - Jun)	$1,264,330,242	$658,658,911	52.1%
2009 (Jan - Jun)	$705,169,075	$362,534,944	51.4%
2010 (Jan - Jun)	$750,901,395	$377,493,236	50.3%
2011 (Jan - Jun)	$701,484,455	$308,396,864	44.0%

Monthly Marginal Loss Costs

Table 2-39 Marginal loss costs by type (Dollars (Millions)): January through June 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
Total	$141.0	($542.8)	$44.3	$728.1	$13.4	$12.4	($27.5)	($26.6)	$701.5

Zonal Marginal Loss Costs

Table 2-40 Marginal loss costs by control zone and type (Dollars (Millions)): January through June 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	$15.0	$2.8	$0.4	$12.6	$0.2	($0.4)	($0.3)	$0.4	$13.0
AEP	($32.5)	($185.5)	$17.5	$170.5	$1.0	$6.0	($6.4)	($11.4)	$159.2
AP	$0.5	($50.2)	$4.3	$54.9	$1.2	$1.8	($1.8)	($2.4)	$52.5
ATSI	($2.4)	($4.2)	$0.3	$2.2	$0.1	$0.4	($0.4)	($0.7)	$1.5
BGE	$33.3	$7.2	$2.7	$28.7	$1.5	($0.7)	($2.3)	($0.1)	$28.6
ComEd	($117.9)	($238.3)	$5.9	$126.3	$9.2	$2.1	($0.4)	$6.8	$133.1
DAY	($1.1)	($28.8)	$3.1	$30.8	($0.1)	$1.8	($1.5)	($3.4)	$27.4
DLCO	($8.2)	($16.8)	$0.6	$9.2	($1.0)	$0.0	($0.4)	($1.5)	$7.7
Dominion	$32.9	($29.8)	$3.0	$65.6	$1.5	($0.4)	($5.7)	($3.9)	$61.8
DPL	$32.5	$4.3	$0.7	$28.9	($1.6)	$0.0	($0.6)	($2.3)	$26.6
JCPL	$35.3	$13.9	$0.3	$21.7	$0.3	($0.1)	($0.3)	$0.1	$21.8
Met-Ed	$8.2	($0.3)	$0.2	$8.7	$0.3	($0.2)	($0.1)	$0.3	$9.0
PECO	$42.9	$14.3	$0.5	$29.1	($0.1)	$0.1	($0.4)	($0.6)	$28.4
PENELEC	($2.9)	($34.5)	($0.2)	$31.4	$1.1	$0.1	$0.5	$1.4	$32.8
Pepco	$31.9	$7.0	$2.8	$27.8	($0.9)	($0.8)	($2.2)	($2.4)	$25.4
PJM	($7.4)	($19.3)	($7.4)	$4.4	($0.9)	($3.8)	$1.3	$4.2	$8.6
PPL	$23.0	($1.5)	$1.5	$25.9	$1.7	$0.8	($0.5)	$0.4	$26.3
PSEG	$56.2	$16.3	$8.0	$47.9	($0.1)	$5.9	($5.9)	($12.0)	$35.9
RECO	$1.8	$0.4	$0.1	$1.4	$0.0	($0.4)	($0.1)	$0.3	$1.8
Total	$141.0	($542.8)	$44.3	$728.1	$13.4	$12.4	($27.5)	($26.6)	$701.5

Table 2-41 Monthly marginal loss costs by control zone (Dollars (Millions)): January through June 2011 (See 2010 SOM, Table 2-60)

	Marginal Loss Costs by Control Zone (Millions)						
	Jan	Feb	Mar	Apr	May	Jun	Grand Total
AECO	$2.9	$2.0	$1.8	$1.5	$1.5	$3.2	$13.0
AEP	$41.9	$25.6	$23.8	$19.2	$18.2	$30.5	$159.2
AP	$14.3	$8.4	$7.7	$6.5	$6.6	$9.1	$52.5
ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$1.5	$1.5
BGE	$6.5	$5.0	$3.9	$3.2	$3.8	$6.3	$28.6
ComEd	$32.3	$21.9	$23.1	$17.8	$15.3	$22.7	$133.1
DAY	$5.2	$5.0	$4.5	$2.8	$4.1	$5.9	$27.4
DLCO	$2.2	$1.6	$0.7	$0.8	$1.2	$1.2	$7.7
Dominion	$19.8	$11.6	$9.7	$4.3	$8.2	$8.2	$61.8
DPL	$7.7	$5.3	$3.6	$2.7	$2.6	$4.7	$26.6
JCPL	$6.2	$4.1	$3.1	$2.5	$2.3	$3.6	$21.8
Met-Ed	$2.1	$1.4	$1.4	$1.2	$1.5	$1.6	$9.0
PECO	$6.6	$3.5	$3.5	$3.7	$4.9	$6.3	$28.4
PENELEC	$8.9	$5.3	$3.6	$3.1	$5.0	$6.9	$32.8
Pepco	$5.9	$3.7	$3.9	$3.1	$3.7	$5.1	$25.4
PJM	$6.9	$4.3	$0.2	($0.6)	$0.1	($2.4)	$8.6
PPL	$8.6	$4.7	$3.0	$2.6	$3.1	$4.4	$26.3
PSEG	$7.3	$6.1	$6.3	$4.6	$5.2	$6.4	$35.9
RECO	$0.5	$0.3	$0.3	$0.2	$0.2	$0.3	$1.8
Total	$185.7	$119.9	$104.0	$79.2	$87.3	$125.4	$701.5

Virtual Offers and Bids

Table 2-42 Monthly volume of cleared and submitted INCs, DECs: January through June 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
Apr	7,222	12,516	185	984	10,211	16,199	202	846
May	7,443	12,161	220	835	10,250	15,956	243	800
Jun	8,405	14,171	238	1,084	11,648	17,542	279	1,015
Annual	7,817	13,726	213	1,110	10,786	16,878	233	938

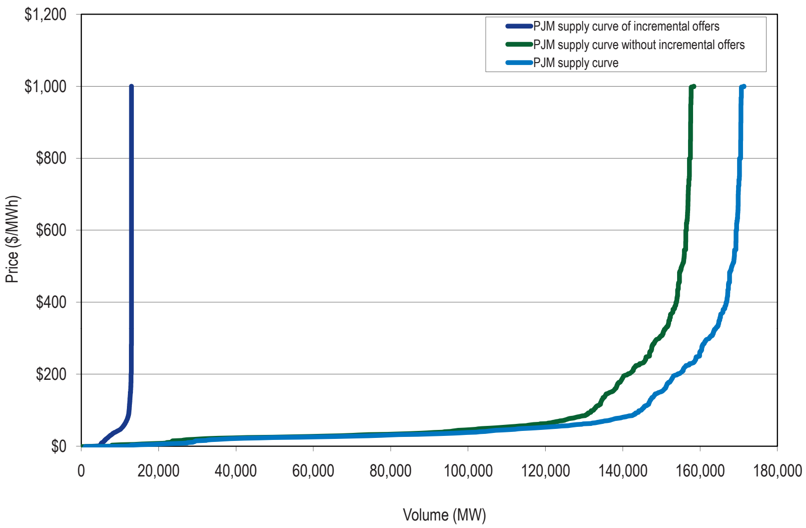
Table 2-43 PJM virtual bids by type of bid parent organization (MW): January through June 2011 (See 2010 SOM, Table 2-63)

Jan - Jun	Category	Total Virtual Bids MW	Percentage
2011	Financial	65,263,359	49.1%
2011	Physical	67,647,808	50.9%
2011	Total	132,911,167	100.0%

Table 2-44 PJM virtual offers and bids by top ten aggregates (MW): January through June 2011 (See 2010 SOM, Table 2-64)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	13,521,348	15,020,627	28,541,975
N ILLINOIS HUB	HUB	5,167,001	8,250,732	13,417,732
AEP-DAYTON HUB	HUB	2,982,170	3,496,006	6,478,176
PECO	ZONE	888,857	2,386,768	3,275,624
MISO	INTERFACE	139,799	2,746,674	2,886,472
SOUTHIMP	INTERFACE	2,829,561	0	2,829,561
PPL	ZONE	148,840	1,910,488	2,059,328
SRIVER 230 KV NUG GE	GEN	799,726	796,024	1,595,750
ComEd	ZONE	1,336,079	193,406	1,529,485
BGE	ZONE	71,238	1,261,260	1,332,498
Top ten total		27,884,617	36,061,984	63,946,601
PJM total		59,610,629	73,300,538	132,911,167
Top ten total as percent of PJM total		47.0%	49.0%	48.0%

Figure 2-22 PJM day-ahead aggregate supply curves: 2011 example day (See 2010 SOM, Figure 2-18)



Price Convergence

Table 2-45 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2011 (See 2010 SOM, Table 2-65)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$44.75	$45.51	$0.76	1.7%
Median	$40.85	$37.40	($3.45)	(9.2%)
Standard deviation	$19.53	$32.52	$12.99	39.9%
Peak average	$52.44	$54.09	$1.64	3.0%
Peak median	$47.54	$42.58	($4.96)	(11.6%)
Peak standard deviation	$22.28	$40.61	$18.32	45.1%
Off peak average	$37.89	$37.86	($0.03)	(0.1%)
Off peak median	$34.62	$33.44	($1.18)	(3.5%)
Off peak standard deviation	$13.38	$20.16	$6.77	33.6%

Table 2-46 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2000 through 2011 (See 2010 SOM, Table 2-66)

Jan - Jun	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$30.29	$27.19	($3.10)	(10.2%)
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%

Table 2-47 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2007 through June 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	0.02%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	27	0.64%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	2,773	64.49%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	1,414	97.05%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	105	99.47%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	16	99.84%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.88%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	2	99.93%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.93%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.93%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.93%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.93%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%

Figure 2-23 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through June 2011 (See 2010 SOM, Figure 2-19)

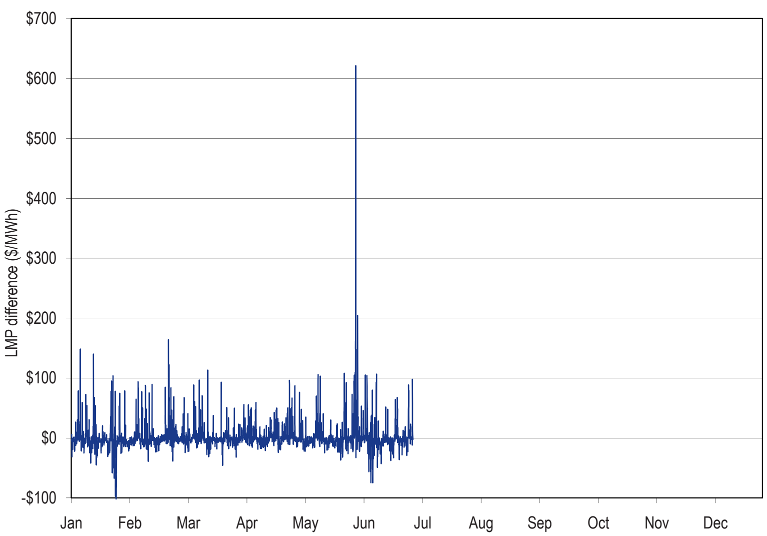
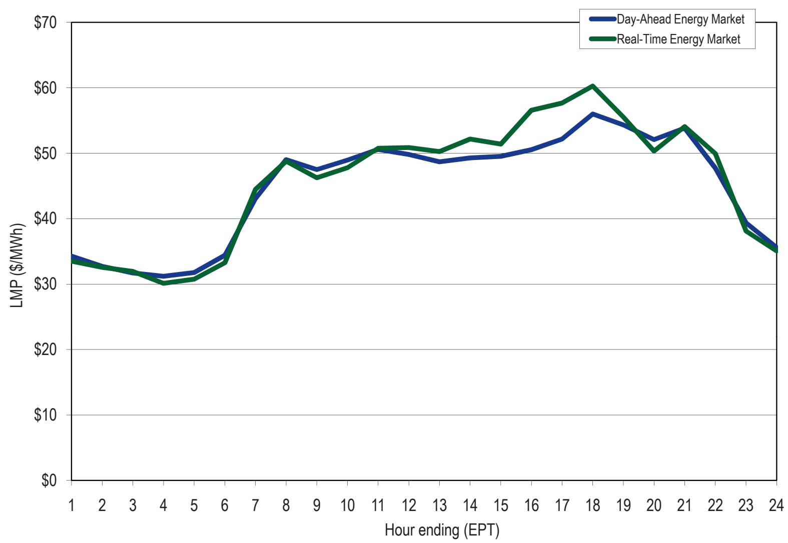


Figure 2-24 Monthly simple average of real-time minus day-ahead LMP: January through June 2011 (See 2010 SOM, Figure 2-20)

Figure 2-25 PJM system simple hourly average LMP: January through June 2011 (See 2010 SOM, Figure 2-21)



Zonal Price Convergence

Table 2-48 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2011 (See 2010 SOM, Table 2-68)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$51.31	$51.33	$0.02	0.0%
AEP	$40.00	$40.15	$0.16	0.4%
AP	$44.98	$45.27	$0.30	0.7%
ATSI	$43.16	$41.94	($1.23)	(2.8%)
BGE	$51.15	$52.07	$0.92	1.8%
ComEd	$34.53	$34.75	$0.22	0.6%
DAY	$39.80	$40.27	$0.47	1.2%
DLCO	$38.94	$39.79	$0.85	2.2%
Dominion	$49.10	$50.17	$1.07	2.2%
DPL	$51.23	$50.93	($0.30)	(0.6%)
JCPL	$51.22	$51.39	$0.17	0.3%
Met-Ed	$49.02	$49.28	$0.27	0.5%
PECO	$50.58	$50.17	($0.40)	(0.8%)
PENELEC	$44.68	$45.14	$0.45	1.0%
Pepco	$50.96	$51.34	$0.38	0.8%
PPL	$49.57	$50.00	$0.42	0.9%
PSEG	$52.16	$52.19	$0.03	0.1%
RECO	$48.48	$45.74	($2.73)	(5.6%)

Price Convergence by Jurisdiction

Table 2-49 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2011 (See 2010 SOM, Table 2-69)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$50.42	$50.27	($0.15)	(0.3%)
Illinois	$34.53	$34.75	$0.22	0.6%
Indiana	$39.04	$39.22	$0.19	0.5%
Kentucky	$39.41	$39.59	$0.18	0.5%
Maryland	$50.75	$51.40	$0.65	1.3%
Michigan	$39.79	$39.87	$0.08	0.2%
New Jersey	$51.72	$51.74	$0.01	0.0%
North Carolina	$47.57	$48.50	$0.92	1.9%
Ohio	$39.73	$40.31	$0.58	1.5%
Pennsylvania	$47.40	$47.59	$0.20	0.4%
Tennessee	$39.91	$39.61	($0.30)	(0.8%)
Virginia	$48.07	$48.76	$0.69	1.4%
West Virginia	$41.45	$41.31	($0.14)	(0.3%)
District of Columbia	$50.94	$51.40	$0.46	0.9%

Load and Spot Market

Real-Time Load and Spot Market

Table 2-50 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2010 through June 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%						
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%	10.5%	27.1%	62.5%	(1.3%)	6.9%	(5.5%)

Day-Ahead Load and Spot Market

Table 2-51 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2010 through June 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%						
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%	5.6%	24.1%	70.2%	0.8%	4.8%	(5.6%)

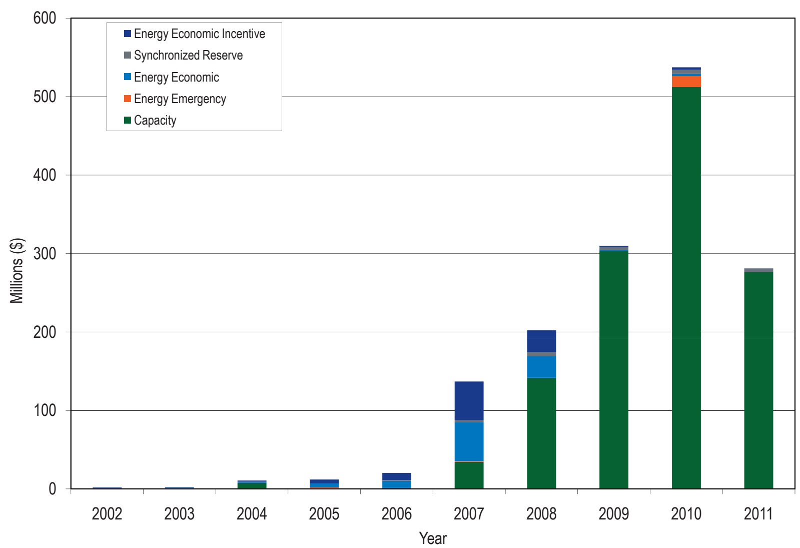
Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-52 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 2-26 Demand Response revenue by market: Calendar years 2002 through 2010 and January through June 2011[10] (See 2010 SOM, Figure 2-22)



10 PJM data currently available show no revenue for the categories "Energy Economic" and "Energy Emergency" for the first six months of 2011.

Economic Program

Table 2-53 Economic Program registration on peak load days: Calendar years 2002 to 2010 and January through June 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
8-Jun-11	834	1,985.1

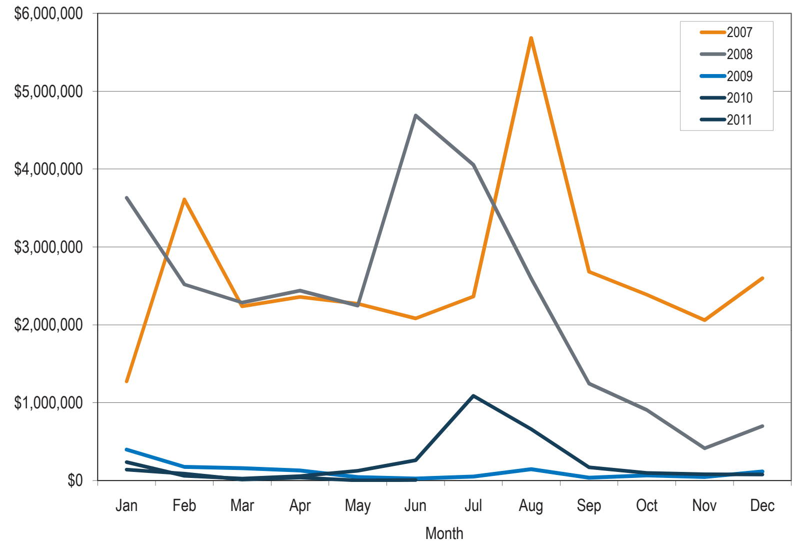
Table 2-54 Economic Program registrations on the last day of the month: January 2008 through June 2011 (See 2010 SOM, Table 2-74)

	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		
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	1,529	2,384

Table 2-55 Distinct registrations and sites in the Economic Program: June 8, 2011[11] (See 2010 SOM, Table 2-75)

	Registrations	Sites	MW
AECO	28	31	13.3
AEP	51	75	134.1
AP	29	41	103.1
ATSI	0	0	0.0
BGE	70	74	903.6
ComEd	68	79	48.1
DAY	5	5	7.2
DLCO	32	36	58.4
Dominion	62	62	181.6
DPL	28	33	62.5
JCPL	22	30	79.4
Met-Ed	46	54	64.1
PECO	180	238	104.3
PENELEC	39	48	50.7
Pepco	14	14	12.7
PPL	88	120	123.3
PSEG	71	128	38.7
RECO	1	1	0.3
Total	834	1,069	1,985.1

Figure 2-27 Economic Program payments by month: Calendar years 2007[12] through 2010 and January through June 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 2-55 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 2-27 do not include these incentive payments.

Table 2-56 PJM Economic Program participation by zone: January through June 2010 and 2011 (See 2010 SOM, Table 2-78)

	Credits			MWh Reductions		
	2010	2011	Percent Change	2010	2011	Percent Change
AECO	$2,262	$0	(100%)	25	0	(100%)
AEP	$0	$0	0%	0	0	0%
AP	$43,037	$7,030	(84%)	2,349	152	(94%)
ATSI	$0	$0	0%	0	0	0%
BGE	$0	$6,336	NA	0	19	NA
ComEd	$15,540	$0	(100%)	1,022	0	(100%)
DAY	$0	$0	0%	0	0	0%
DLCO	$0	$44	NA	0	2	NA
Dominion	$489,404	$216,244	(56%)	8,031	2,381	(70%)
DPL	$0	$0	0%	0	0	0%
JCPL	$948	$0	(100%)	14	0	(100%)
Met-Ed	$310	$0	(100%)	21	0	(100%)
PECO	$198,193	$55,769	(72%)	8,300	1,292	(84%)
PENELEC	$331	$0	(100%)	18	0	(100%)
Pepco	$776	$0	(100%)	17	0	(100%)
PPL	$11,049	$0	(100%)	422	3	(99%)
PSEG	$5	$0	0%	4	0	0%
RECO	$0	$0	0%	0	0	0%
Total	$761,854	$285,423	(63%)	20,225	3,848	(81%)

Table 2-57 Settlement days submitted by month in the Economic Program: Calendar years 2007 through 2010 and January through June 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	
Aug	3,962	3,848	3,760	2,158	
Sep	3,388	3,264	2,570	660	
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	1,935

Table 2-58 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2010 and January through June 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		
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	13	438

Table 2-59 Hourly frequency distribution of Economic Program MWh reductions and credits: January through June 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	0.15%	6	0.15%	$105	0.04%	$105	0.04%
2	6	0.17%	12	0.31%	$193	0.07%	$298	0.10%
3	12	0.32%	24	0.63%	$619	0.22%	$917	0.32%
4	4	0.10%	28	0.74%	$61	0.02%	$978	0.34%
5	8	0.21%	36	0.95%	$51	0.02%	$1,028	0.36%
6	36	0.92%	72	1.87%	$725	0.25%	$1,754	0.61%
7	779	20.24%	851	22.11%	$63,898	22.39%	$65,652	23.00%
8	1,080	28.06%	1,930	50.17%	$99,668	34.92%	$165,320	57.92%
9	450	11.68%	2,380	61.85%	$31,577	11.06%	$196,897	68.98%
10	177	4.60%	2,557	66.44%	$9,281	3.25%	$206,178	72.24%
11	130	3.39%	2,687	69.83%	$4,746	1.66%	$210,924	73.90%
12	98	2.55%	2,785	72.39%	$1,764	0.62%	$212,688	74.52%
13	116	3.02%	2,901	75.40%	$2,158	0.76%	$214,846	75.27%
14	80	2.08%	2,981	77.48%	$3,361	1.18%	$218,207	76.45%
15	95	2.47%	3,076	79.95%	$5,900	2.07%	$224,108	78.52%
16	125	3.25%	3,201	83.20%	$8,684	3.04%	$232,791	81.56%
17	194	5.04%	3,395	88.23%	$12,928	4.53%	$245,719	86.09%
18	194	5.04%	3,589	93.27%	$22,816	7.99%	$268,535	94.08%
19	173	4.50%	3,762	97.77%	$13,686	4.79%	$282,221	98.88%
20	25	0.64%	3,787	98.41%	$1,306	0.46%	$283,527	99.34%
21	26	0.66%	3,812	99.08%	$1,156	0.41%	$284,683	99.74%
22	18	0.47%	3,830	99.54%	$540	0.19%	$285,223	99.93%
23	12	0.30%	3,842	99.85%	$144	0.05%	$285,367	99.98%
24	6	0.15%	3,848	100.00%	$56	0.02%	$285,423	100.00%

Table 2-60 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through June 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	0.15%	6	0.15%	$18	0.01%	$18	0.01%
$25 to $50	736	19.14%	742	19.29%	$8,382	2.94%	$8,400	2.94%
$50 to $75	962	25.01%	1,705	44.30%	$22,118	7.75%	$30,518	10.69%
$75 to $100	305	7.93%	2,010	52.23%	$14,493	5.08%	$45,012	15.77%
$100 to $125	268	6.95%	2,277	59.19%	$14,493	5.08%	$59,505	20.85%
$125 to $150	537	13.95%	2,814	73.13%	$48,311	16.93%	$107,816	37.77%
$150 to $200	431	11.21%	3,246	84.34%	$56,117	19.66%	$163,933	57.44%
$200 to $250	301	7.83%	3,547	92.17%	$50,653	17.75%	$214,586	75.18%
$250 to $300	201	5.22%	3,748	97.39%	$41,869	14.67%	$256,455	89.85%
> $300	100	2.61%	3,848	100.00%	$28,968	10.15%	$285,423	100.00%

Emergency Program

Load Management Program

Table 2-61 Zonal monthly capacity credits: January through June 2011 (See 2010 SOM, Table 2-85)

Zone	January	February	March	April	May	June	Total
AECO	$515,251	$465,388	$515,251	$498,630	$515,251	$332,740	$2,842,509
AEP	$7,718,744	$6,971,769	$7,718,744	$7,469,752	$7,718,744	$5,220,226	$42,817,980
APS	$4,272,819	$3,859,321	$4,272,819	$4,134,986	$4,272,819	$3,300,774	$24,113,539
ATSI	$0	$0	$0	$0	$0	$4,665	$4,665
BGE	$5,039,828	$4,552,103	$5,039,828	$4,877,253	$5,039,828	$3,513,455	$28,062,294
ComEd	$8,156,971	$7,367,587	$8,156,971	$7,893,843	$8,156,971	$5,965,794	$45,698,137
DAY	$1,151,545	$1,040,105	$1,151,545	$1,114,399	$1,151,545	$797,889	$6,407,029
DLCO	$5,447,494	$4,920,317	$5,447,494	$5,271,768	$5,447,494	$3,851,851	$30,386,419
Dominion	$1,088,233	$982,920	$1,088,233	$1,053,128	$1,088,233	$790,970	$6,091,718
DPL	$1,118,544	$1,010,298	$1,118,544	$1,082,462	$1,118,544	$2,340	$5,450,733
JCPL	$1,301,034	$1,175,128	$1,301,034	$1,259,066	$1,301,034	$854,729	$7,192,025
Met-Ed	$1,205,089	$1,088,468	$1,205,089	$1,166,215	$1,205,089	$880,176	$6,750,126
PECO	$2,826,229	$2,552,723	$2,826,229	$2,735,060	$2,826,229	$2,300,272	$16,066,741
PENELEC	$1,827,610	$1,650,744	$1,827,610	$1,768,654	$1,827,610	$1,335,716	$10,237,944
Pepco	$1,307,359	$1,180,840	$1,307,359	$1,265,186	$1,307,359	$1,137,037	$7,505,139
PPL	$4,115,164	$3,716,922	$4,115,164	$3,982,417	$4,115,164	$2,651,235	$22,696,067
PSEG	$2,536,813	$2,291,315	$2,536,813	$2,454,980	$2,536,813	$1,431,581	$13,788,316
RECO	$9,266	$8,369	$9,266	$8,967	$9,266	$21,799	$66,934
Total	$49,637,993	$44,834,317	$49,637,993	$48,036,767	$49,637,993	$34,393,250	$276,178,314