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 2010, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2010.

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

1 Analysis of 2010 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

2 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," First Revised Sheet No. 448.05 (Effective June 29, 2009).

Overview

Market Structure

- **Supply.** During the second quarter of 2010, the PJM Energy Market received an hourly average of 155,015 MW in supply offers including hydroelectric generation.[3] The second quarter 2010 average daily offered supply was 646 MW higher than the second quarter 2009 average daily offered supply of 154,369 MW.

- **Demand.** The PJM system peak load for the second quarter 2010 was 126,188 MW in the hour ended 1700 EPT on June 23, 2010, while the PJM peak load for the second quarter 2009 was 116,751 MW in the hour ended 1700 EPT on June 25, 2009.[4] The second quarter 2010 peak load was 9,437 MW, or 8.1 percent, higher than the second quarter 2009 peak load.

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

- **Local Market Structure and Offer Capping.** A noncompetitive local market structure is the trigger for offer capping. PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2010. PJM offer caps units only when the local market structure is noncompetitive. Offer

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

4 For the purpose of the *2010 Quarterly State of the Market Report for PJM: January through June*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2009 State of the Market Report for PJM*, Appendix N, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.1 percent in 2009 to 0.3 percent in the first six months of 2010. In the Real-Time Energy Market offer-capped unit hours increased from 0.4 percent in 2009 to 1.0 percent in the period from January through June 2010.

As of 9:30 AM on June 9, 2010, PJM replaced LA UDS with new short run look ahead Security Constrained Economic Dispatch (SCED; SCED 2; or IT SCED) optimization software. The three pivotal supplier test (TPS) is now run in SCED. Each pass of the SCED 2 software produces multiple security constrained optimization and unit commitment results for anticipated system conditions fifteen to one hundred and twenty minutes into the future. Generally, there is a SCED 2 pass every 15 minutes. The TPS test is calculated for any constraints that require incremental relief in each of the forward market solutions generated by each pass of the SCED 2 software. For example, this means that a SCED 2 pass that produces results for 15, 30, 45 and 120 minutes in the future will have four complete sets of TPS results, one set for each forward market solution. Each pass of the LA UDS produced only one set of TPS results.

- **Local Market Structure.** For the period January 1, 2010, through June 8, 2010, a summary of the TPS results based on the LA UDS is presented for all constraints which occurred for 50 or more hours during the first six months of calendar year 2010. For the period June 9, 2010 (9:30 AM), through June 30, 2010, a summary of the TPS results based on SCED is presented for all regional 500 kV constraints.

  During the first six months of 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, 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 three pivotal supplier test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, as such a full redispatch is practically impossible because it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

  The markup component of the overall PJM real-time, load-weighted, average LMP for the first six months of 2010 was -$1.15 per MWh, or -2.5 percent. Coal steam units contributed -$1.74, or 151.9 percent, to the total markup component of LMP. Combustion turbine units that use natural gas as their primary fuel source contributed $0.22 or -19.5 percent to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.29 or -25.7 percent to the total markup component of LMP. The markup was -$0.59 per MWh during peak hours and -$1.73 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP for the first six months of 2010 was -$1.12 per MWh, or -2.4 percent. Coal steam units contributed -$0.97 or 87.0 percent to the total markup component of LMP. Natural gas steam units contributed -$0.14 or 12.4 percent to the total markup component of LMP. The markup was -$0.65 per MWh during peak hours and -$1.61 per MWh during off-peak hours.

  The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** On average, PJM real-time load increased in the first six months of 2010 by 2.8 percent from the first six months of 2009, rising from 75,993 MW to 78,106 MW. PJM day-ahead load increased in the first six months of 2010 by 1.3 percent from the first six months of 2009, rising from 88,688 MW to 89,830 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 and local price differences caused by congestion.

  PJM Real-Time Energy Market prices increased in the first six months of 2010 compared to the first six months of 2009. The system simple average LMP was 7.9 percent higher in the first six months of 2010 than in the first six months of 2009, $43.27 per MWh versus $40.12 per MWh. The load-weighted LMP was 7.7 percent higher in the first six months of 2010 than the first six months of 2009, $45.75 per MWh versus $42.48 per MWh. The real-time, fuel cost adjusted, load-weighted, average LMP was 17.3 percent higher for the first six months of 2010 than the load-weighted, average LMP for the first six months of 2009, $49.81 per MWh versus $42.48 per MWh. In other words, if fuel costs in the first six months of 2010 were the same as they had been in the first six months of 2009, the 2010 load-weighted LMP would have been higher, $49.81 per MWh, than the actual $45.75 per MWh, and 17.3 percent higher than the load-weighted average LMP for the first six months of 2009. Higher loads contributed to upward pressure on LMP while fuel costs contributed to downward pressure on LMP in the first half of 2010.

  PJM Day-Ahead Energy Market prices increased in the first six months of 2010 compared to the first six months of 2009. The system simple average LMP was 9.5 percent higher in the first six months of 2010 than in the first six months of 2009, $43.81 per MWh versus $40.01 per MWh. The load-weighted LMP was 9.3 percent higher in the first six months of 2010 than in the first six months of 2009, $46.12 per MWh versus $42.21 per MWh.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a PJM parent company that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first six months of 2010, 12.0 percent of real-time load was supplied by bilateral contracts, 18.6 percent by spot market purchases and 69.4 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 0.8 percentage points; reliance on spot supply increased by 1.6 percentage points; and reliance on self-supply decreased by 0.7 percentage points in 2010.

Demand-Side Response

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

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

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

- **Demand-Side Response Activity.** In the first six months of 2010, in the Economic Program, participation decreased compared to the first six months of 2009. There were decreases in a range of activity metrics including settlements submitted, settled MWh and credits. Participation levels through calendar year 2009 and through the first six months of 2010 are generally 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 2010 (June 23, 2010), there were 1,891.5 MW registered in the Economic Load Response Program.

In the first six months of 2010, the Emergency Program, specifically, the Load Management (LM) Program, participation increased compared to the same period in 2009.[5] Participants in the LM Program are committed resources that receive RPM capacity credits and participation continues to increase through RPM delivery years. For the 2010/2011 delivery year, there were 9,052.4 MW registered in the LM Program, compared to 7,294.3 MW registered in the 2009/2010 delivery year.

Since the introduction of the RPM capacity market on June 1, 2007 the capacity market has been the source of growth in total demand side revenues and demand side revenues from the capacity market were the only significant source of revenue in 2009 and through the first six months of 2010. In the first six months of 2010, payments from the Economic Program decreased from the first six months of 2009 by $410,000 or 48 percent, from $853,000 to $443,000 while capacity revenue increased from the first six months of 2009 by $101 million or 89 percent, from $114 million to $214 million since 2009.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the first six months of 2010, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply increased by about 646 MW when comparing the second quarter of 2010 to the second quarter of 2009, while aggregate peak load increased by 9,437 MW, modifying the general supply demand balance from the second quarter of 2009 with a corresponding impact on Energy Market prices. Average load in the first six months of 2010 also increased from the first six months of 2009. Market concentration levels remained moderate and average markup was negative. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

5 The Capacity Only and Full options of the Emergency Program are integrated into RPM through the Load Management Program. The Energy Only option is a voluntary program that does not interact with RPM, however, there are currently no participants registered in this option.

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

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

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

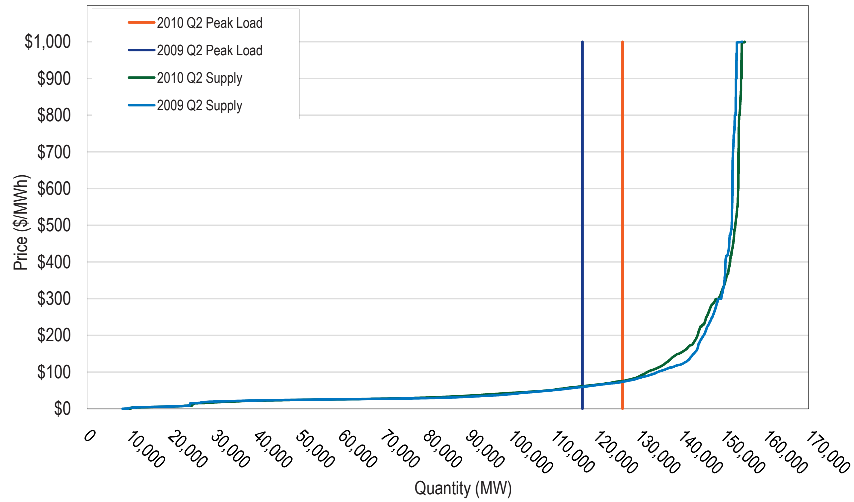
Energy Market results for the first six months of 2010 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher demand, mitigated by lower fuel costs. PJM Real-Time, load-weighted, average LMP for the first six months of 2010 was $45.75, or 7.7 percent higher than the load-weighted, average LMP for the first six months of 2009, which was $42.48. The real-time fuel cost adjusted, load-weighted, average LMP was 17.3 percent higher for the first six months of 2010 than the load-weighted, average LMP in for the first six months of 2009, $49.81 per MWh compared to $42.48 per MWh. In other words, if fuel costs in the first six months of 2010 were the same as they had been in the first six months of 2009, the 2010 load-weighted LMP would have been higher, $49.81 per MWh, than the actual $45.75 per MWh, and 17.3 percent higher than the load-weighted average LMP for the first six months of 2009. Higher loads contributed to upward pressure on LMP while fuel costs contributed to downward pressure on LMP in the first half of 2010.

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

Market Structure

Supply

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



Demand

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

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)	Difference (%)
2003	Wed, June 25	17	61,310	NA	NA
2004	Wed, June 09	17	77,676	16,366	26.7%
2005	Tue, June 28	16	124,052	46,375	59.7%
2006	Tue, May 30	17	121,165	(2,887)	(2.3%)
2007	Wed, June 27	16	130,971	9,806	8.1%
2008	Mon, June 09	17	130,100	(871)	(0.7%)
2009	Thu, June 25	17	116,751	(13,349)	(10.3%)
2010	Wed, June 23	17	126,188	9,438	8.1%

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

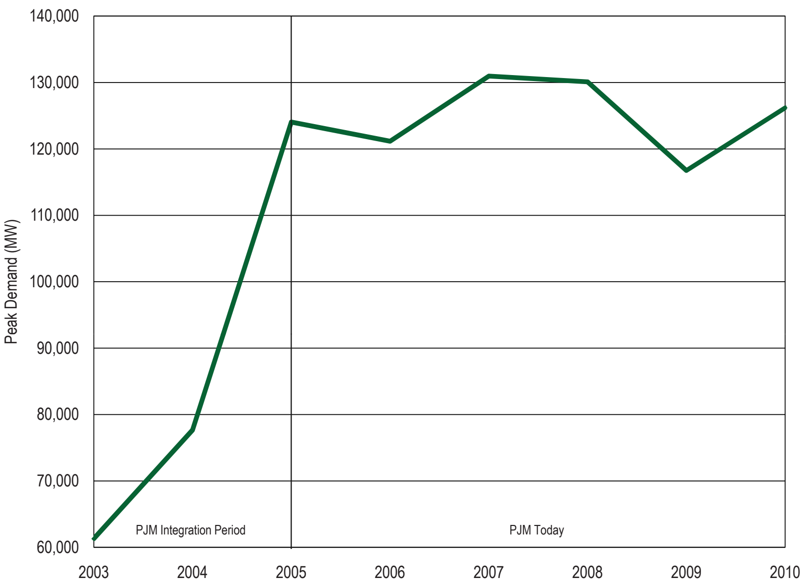
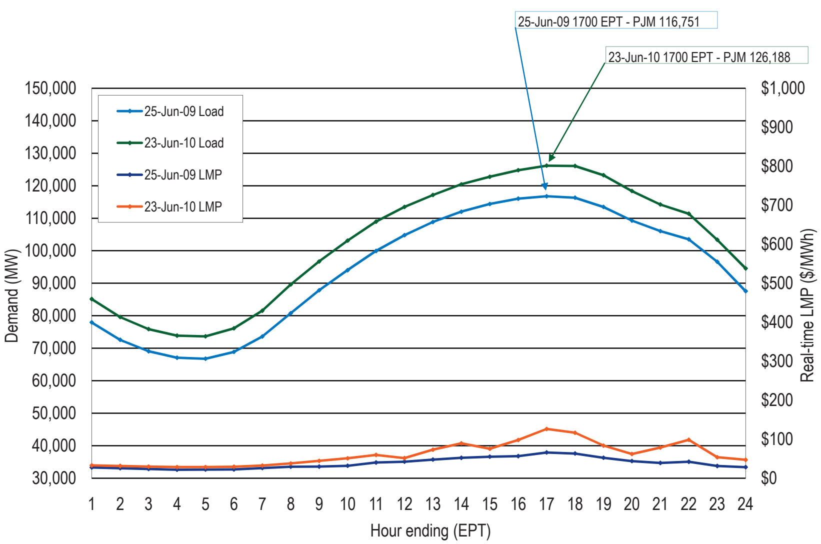


Figure 2-3 PJM second quarter peak-load comparison: Wednesday, June 23, 2010 and Thursday, June 25, 2009 (See 2009 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

Table 2-2 PJM hourly Energy Market HHI: January through June 2010[6] (See 2009 SOM, Table 2-2)

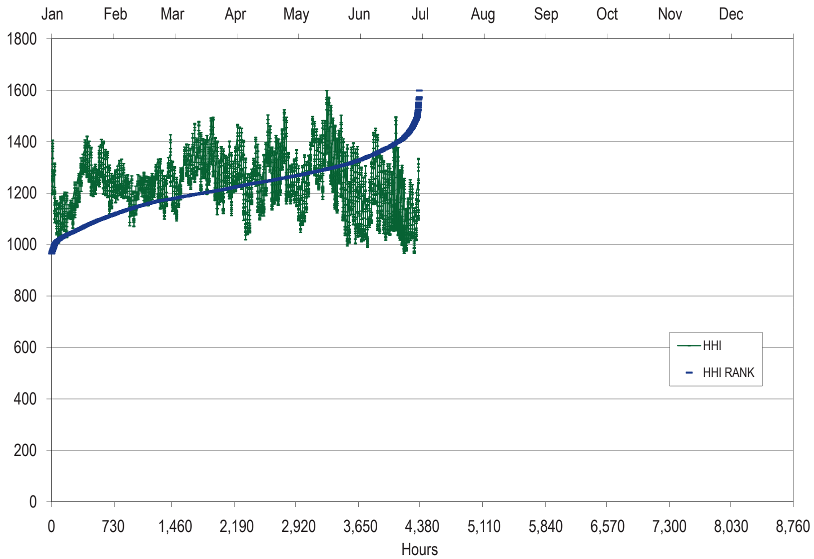
	Hourly Market HHI
Average	1222
Minimum	966
Maximum	1599
Highest market share (One hour)	31%
Highest market share (All hours)	21%
# Hours	4,343
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

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

	Minimum	Average	Maximum
Base	1125	1273	1567
Intermediate	689	1898	9079
Peak	728	5878	10000

6 This analysis includes all hours of the first six months of 2010, regardless of congestion.

Figure 2-4 PJM hourly Energy Market HHI: January through June 2010 (See 2009 SOM, Figure 2-4)



Local Market Structure and Offer Capping

Table 2-4 Annual real-time offer-capping statistics: Calendar years 2006 through June 2010 (See 2009 SOM, Table 2-4)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.0%	0.3%	0.3%	0.1%

Table 2-5 Real-time offer-capped unit statistics: January through June 2010 (See 2009 SOM, Table 2-5)

	2010 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	1	1	0	1	1	57
80% and < 90%	0	0	0	0	1	27
75% and < 80%	2	0	0	0	0	6
70% and < 75%	0	0	0	0	1	3
60% and < 70%	0	0	0	0	3	19
50% and < 60%	0	0	0	0	2	28
25% and < 50%	1	0	0	2	2	47
10% and < 25%	0	1	1	1	2	39

Local Market Structure[7]

Table 2-6 Look ahead UDS based three pivotal supplier results summary for regional constraints: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-6)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	720	625	87%	180	25%
	Off Peak	465	408	88%	114	25%
AP South	Peak	2,106	1,102	52%	1,462	69%
	Off Peak	1,734	949	55%	1,132	65%
Bedington - Black Oak	Peak	167	138	83%	48	29%
	Off Peak	34	17	50%	23	68%
Central	Peak	6	6	100%	0	0%
	Off Peak	NA	NA	NA	NA	NA
Harrison - Pruntytown	Peak	116	105	91%	25	22%
	Off Peak	281	204	73%	136	48%
West	Peak	114	108	95%	9	8%
	Off Peak	43	37	86%	8	19%

Table 2-7 SCED 2 based three pivotal supplier results summary for regional constraints: June 9, 2010 through June 30, 2010 (See 2009 SOM, Table 2-6)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	553	10	2%	548	99%
	Off Peak	28	2	7%	27	96%
AP South	Peak	2,764	26	1%	2,758	100%
	Off Peak	1,474	18	1%	1,471	100%
Harrison - Pruntytown	Peak	55	0	0%	55	100%
	Off Peak	NA	NA	NA	NA	NA

7 Effective June 9, 2010, at 9:30 AM, the three pivotal supplier test (TPS) was run in PJM's new short run look ahead Security Constrained Economic Dispatch (SCED) optimization software instead of the Look-Ahead Unit Dispatch Software (LA UDS). For the period January 1, 2010, through June 8, 2010, the MMU is reporting all LA UDS based TPS results for all the transmission constraints with 50 or more constrained hours For the period June 9, 2010, starting at 9:30 am, through June 30, 2010, the MMU is reporting SCED 2 based TPS results for regional 500 kv constraints.

Table 2-8 Look ahead UDS based three pivotal supplier test details for regional constraints: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-7)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	76	279	19	16	3
	Off Peak	58	260	18	16	3
AP South	Peak	76	234	11	5	6
	Off Peak	73	243	10	5	5
Bedington - Black Oak	Peak	48	158	16	13	3
	Off Peak	102	187	14	5	9
Central	Peak	139	1,333	21	21	0
	Off Peak	NA	NA	NA	NA	NA
Harrison - Pruntytown	Peak	64	308	20	17	2
	Off Peak	63	210	17	11	5
West	Peak	125	712	19	17	1
	Off Peak	111	640	22	19	3

Table 2-9 SCED 2 based three pivotal supplier test details for regional constraints: June 8, 2010 through June 30, 2010 (See 2009 SOM, Table 2-7)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	545	2,069	17	0	17
	Off Peak	416	1,512	13	1	13
AP South	Peak	391	946	8	0	8
	Off Peak	476	1,103	8	0	8
Harrison - Pruntytown	Peak	252	551	8	0	8
	Off Peak	NA	NA	NA	NA	NA

Table 2-10 Three pivotal supplier results summary for constraints located in the AECO Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-10)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
England - Middletap	Peak	52	0	0%	52	100%
	Off Peak	106	0	0%	106	100%

Table 2-11 Three pivotal supplier test details for constraints located in the AECO Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-11)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
England - Middletap	Peak	3	33	2	0	2
	Off Peak	4	35	2	0	2

Table 2-12 Three pivotal supplier results summary for constraints located in the AEP Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-12)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Baker - Broadford	Peak	62	17	27%	48	77%
	Off Peak	276	140	51%	210	76%
Cloverdale - Lexington	Peak	152	89	59%	87	57%
	Off Peak	1,021	473	46%	740	72%
Conesville - Prep Plant Tap	Peak	271	0	0%	271	100%
	Off Peak	8	0	0%	8	100%
Mahans Lane - Tidd	Peak	158	0	0%	158	100%
	Off Peak	13	0	0%	13	100%

Table 2-13 Three pivotal supplier test details for constraints located in the AEP Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-13)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Baker - Broadford	Peak	40	124	9	2	7
	Off Peak	66	215	9	4	6
Cloverdale - Lexington	Peak	78	211	17	10	7
	Off Peak	75	163	14	5	9
Conesville - Prep Plant Tap	Peak	12	35	2	0	2
	Off Peak	10	46	2	0	2
Mahans Lane - Tidd	Peak	8	11	1	0	1
	Off Peak	3	9	2	0	2

Table 2-14 Three pivotal supplier results summary for constraints located in the AP Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-14)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Albright - Mt. Zion	Peak	185	0	0%	185	100%
	Off Peak	254	0	0%	254	100%
Doubs	Peak	834	255	31%	652	78%
	Off Peak	163	40	25%	144	88%
Middlebourne - Willow	Peak	208	0	0%	208	100%
	Off Peak	223	0	0%	223	100%
Mount Storm - Pruntytown	Peak	18	18	100%	3	17%
	Off Peak	291	157	54%	179	62%
Tiltonsville - Windsor	Peak	937	0	0%	937	100%
	Off Peak	627	0	0%	627	100%
Wylie Ridge	Peak	NA	NA	NA	NA	NA
	Off Peak	178	152	85%	57	32%

Table 2-15 Three pivotal supplier test details for constraints located in the AP Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-15)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Albright - Mt. Zion	Peak	8	5	1	0	1
	Off Peak	14	6	1	0	1
Doubs	Peak	22	38	8	4	4
	Off Peak	19	46	8	2	6
Middlebourne - Willow	Peak	9	2	1	0	1
	Off Peak	11	2	1	0	1
Mount Storm - Pruntytown	Peak	27	265	9	8	1
	Off Peak	81	239	10	6	5
Tiltonsville - Windsor	Peak	9	4	2	0	2
	Off Peak	10	5	2	0	2
Wylie Ridge	Peak	NA	NA	NA	NA	NA
	Off Peak	29	125	16	13	3

Table 2-16 Three pivotal supplier results summary for constraints located in the BGE Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-16)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Brandon Shores - Riverside	Peak	168	138	82%	66	39%
	Off Peak	4	4	100%	2	50%
Graceton - Raphael Road	Peak	232	170	73%	108	47%
	Off Peak	47	38	81%	23	49%

Table 2-17 Three pivotal supplier test details for constraints located in the BGE Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-17)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brandon Shores - Riverside	Peak	21	112	16	13	3
	Off Peak	25	88	19	18	2
Graceton - Raphael Road	Peak	43	122	18	13	6
	Off Peak	49	142	17	12	5

Table 2-18 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-18)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Burnham - Munster	Peak	31	21	68%	10	32%
	Off Peak	406	123	30%	320	79%
East Frankfort - Crete	Peak	187	17	9%	178	95%
	Off Peak	3,520	66	2%	3,489	99%
Electric Jct - Nelson	Peak	49	0	0%	49	100%
	Off Peak	111	0	0%	111	100%
Pleasant Valley - Belvidere	Peak	348	0	0%	348	100%
	Off Peak	489	0	0%	489	100%
Waterman - West Dekalb	Peak	264	0	0%	264	100%
	Off Peak	446	0	0%	446	100%
Wilton Center	Peak	45	27	60%	19	42%
	Off Peak	505	53	10%	475	94%
Zion - Pleasant Prairie	Peak	266	0	0%	266	100%
	Off Peak	265	0	0%	265	100%

Table 2-19 Three pivotal supplier test details for constraints located in the ComEd Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-19)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Munster	Peak	25	97	22	15	6
	Off Peak	40	81	13	4	9
East Frankfort - Crete	Peak	33	116	6	1	5
	Off Peak	33	43	4	0	4
Electric Jct - Nelson	Peak	33	1	1	0	1
	Off Peak	28	3	2	0	2
Pleasant Valley - Belvidere	Peak	11	3	1	0	1
	Off Peak	11	1	1	0	1
Waterman - West Dekalb	Peak	9	0	1	0	1
	Off Peak	9	1	1	0	1
Wilton Center	Peak	27	108	17	13	4
	Off Peak	39	44	7	1	6
Zion - Pleasant Prairie	Peak	57	8	2	0	2
	Off Peak	55	6	2	0	2

Table 2-20 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-20)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Collier - Elwyn	Peak	533	0	0%	533	100%
	Off Peak	51	0	0%	51	100%
Crescent	Peak	757	0	0%	757	100%
	Off Peak	NA	NA	NA	NA	NA

Table 2-21 Three pivotal supplier test details for constraints located in the DLCO Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-21)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Collier - Elwyn	Peak	15	7	1	0	1
	Off Peak	15	9	1	0	1
Crescent	Peak	16	5	1	0	1
	Off Peak	NA	NA	NA	NA	NA

Table 2-22 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-22)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Beechwood - Kerr Dam	Peak	176	0	0%	176	100%
	Off Peak	150	0	0%	150	100%
Bremo - Kidds Store	Peak	275	0	0%	275	100%
	Off Peak	125	0	0%	125	100%
Clover	Peak	191	33	17%	183	96%
	Off Peak	6	0	0%	6	100%
Danville - East Danville	Peak	91	0	0%	91	100%
	Off Peak	218	1	0%	217	100%
Fredericksburg	Peak	139	0	0%	139	100%
	Off Peak	10	0	0%	10	100%
Pleasant View	Peak	276	199	72%	106	38%
	Off Peak	8	0	0%	8	100%

Table 2-23 Three pivotal supplier test details for constraints located in the Dominion Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-23)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	4	8	1	0	1
	Off Peak	4	3	1	0	1
Bremo - Kidds Store	Peak	7	19	1	0	1
	Off Peak	6	13	1	0	1
Clover	Peak	25	89	6	1	6
	Off Peak	8	43	5	0	5
Danville - East Danville	Peak	21	24	4	0	4
	Off Peak	16	14	3	0	3
Fredericksburg	Peak	8	82	1	0	1
	Off Peak	19	53	1	0	1
Pleasant View	Peak	46	118	19	14	5
	Off Peak	29	42	9	0	9

Table 2-24 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-30)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Athenia - Saddlebrook	Peak	1,169	1	0%	1,169	100%
	Off Peak	341	0	0%	341	100%
Branchburg - Readington	Peak	204	0	0%	204	100%
	Off Peak	3	0	0%	3	100%

Table 2-25 Three pivotal supplier test details for constraints located in the PSEG Control Zone: January 1, 2010 through June 8, 2010 (See 2009 SOM, Table 2-31)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	12	40	2	0	2
	Off Peak	10	38	1	0	1
Branchburg - Readington	Peak	21	91	2	0	2
	Off Peak	10	95	3	0	3

Market Performance: Markup

Real-Time Markup

Ownership of Marginal Resources

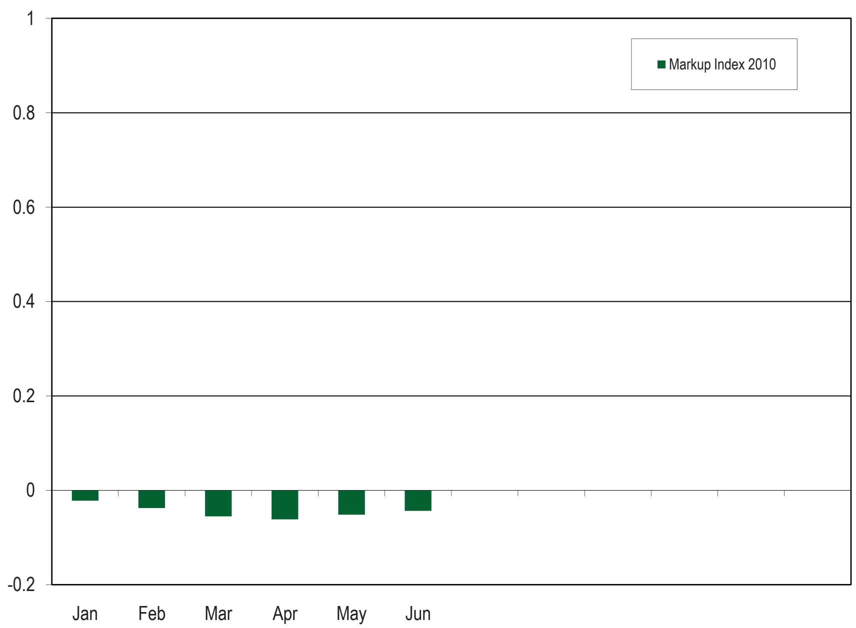
Table 2-26 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through June 2010 (See 2009 SOM, Table 2-32)

Company	Percent of Price
1	18%
2	14%
3	11%
4	6%
5	5%
6	5%
7	4%
8	3%
9	3%
Other (50 companies)	31%

Table 2-27 Type of fuel used (By real-time marginal units): January through June 2010 (See 2009 SOM, Table 2-33)

Fuel Type	2010
Coal	68%
Natural Gas	25%
Petroleum	3%
Wind	2%
Landfill Gas	1%
Misc	1%

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



Unit Markup Characteristics

Table 2-28 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through June 2010 (See 2009 SOM, Table 2-34)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.74)	151.9%
Gas	CC	$0.29	(25.7%)
Gas	CT	$0.22	(19.5%)
Gas	Diesel	($0.00)	0.1%
Gas	Steam	($0.02)	1.6%
Interface	Interface	($0.00)	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.01	(1.2%)
Oil	CT	$0.01	(1.2%)
Oil	Diesel	($0.01)	0.5%
Oil	Steam	$0.03	(3.0%)
Uranium	Steam	$0.00	(0.0%)
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.04	(3.5%)
Total		($1.15)	100.0%

Table 2-29 Average, real-time marginal unit markup index (By price category): January through June 2010 (See 2009 SOM, Table 2-35)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($3.21)
$25 to $50	(0.07)	($2.82)
$50 to $75	0.02	$1.26
$75 to $100	0.06	$4.61
$100 to $125	0.09	$9.29
$125 to $150	0.11	$14.37
> $150	0.05	$11.15

Markup Component of System Price

Table 2-30 Monthly markup components of real-time load-weighted LMP: January through June 2010 (See 2009 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.56	$0.00	$1.03
Feb	($1.53)	($1.19)	($1.88)
Mar	($2.01)	($1.38)	($2.73)
Apr	($2.36)	($2.52)	($2.17)
May	($2.93)	$0.50	($6.14)
Jun	$0.66	$0.75	$0.56
2010	($1.15)	($0.59)	($1.73)

Markup Component of Real-Time Zonal Prices

Table 2-31 Average real-time zonal markup component: January through June 2010 (See 2009 SOM, Table 2-37)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$0.23	$2.27	($1.86)
AEP	($3.56)	($4.47)	($2.63)
AP	($2.23)	($0.87)	($3.62)
BGE	$1.47	$4.49	($1.60)
ComEd	($1.38)	($3.16)	$0.55
DAY	($3.59)	($4.27)	($2.84)
DLCO	($2.28)	($1.59)	($3.02)
Dominion	$0.27	$2.06	($1.54)
DPL	$0.07	$1.47	($1.35)
JCPL	($0.12)	$1.90	($2.33)
Met-Ed	($0.30)	$1.17	($1.87)
PECO	($0.02)	$1.54	($1.65)
PENELEC	($1.68)	($1.41)	($1.96)
Pepco	$0.12	$1.79	($1.64)
PPL	($0.22)	$1.06	($1.58)
PSEG	($0.16)	$1.09	($1.54)
RECO	($0.58)	($0.10)	($1.13)

Markup by Real-Time System Price Levels

Table 2-32 Average real-time markup component (By price category): January through June 2010 (See 2009 SOM, Table 2-38)

	Average Markup Component	Frequency
Below $20	($2.97)	2.0%
$20 to $40	($3.42)	57.4%
$40 to $60	($0.80)	26.7%
$60 to $80	$6.16	7.8%
$80 to $100	($5.78)	3.1%
$100 to $120	$12.45	1.5%
$120 to $140	$15.48	0.9%
$140 to $160	$20.06	0.3%
Above $160	$25.96	0.3%

Day-Ahead Markup

Ownership of Marginal Resources

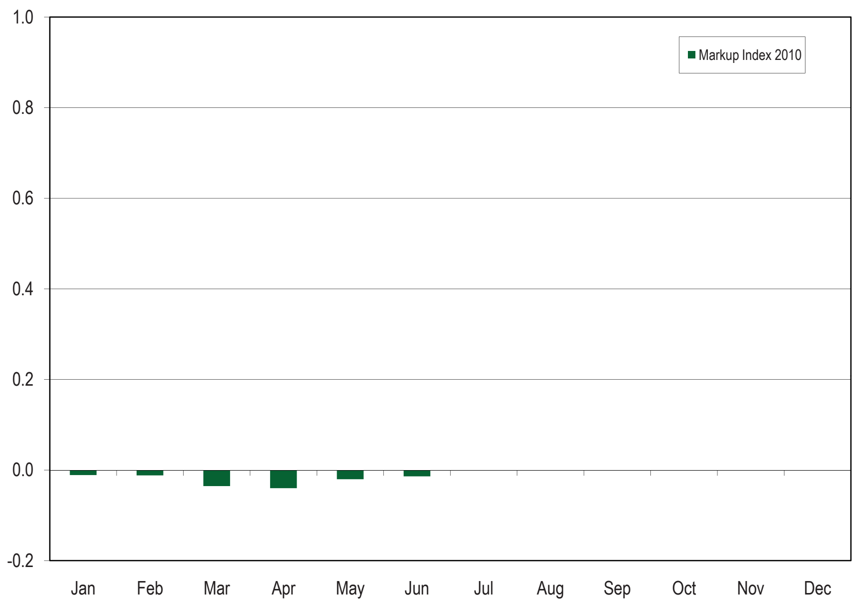
Table 2-33 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through June 2010 (See 2009 SOM, Table 2-39)

Company	Percent of Price
1	25%
2	8%
3	5%
4	5%
5	5%
6	5%
7	4%
8	3%
9	3%
Other (118 companies)	37%

Table 2-34 Day-ahead marginal resources by type/fuel: January through June 2010 (See 2009 SOM, Table 2-40)

Type/Fuel	2010
Transaction	33%
DEC	30%
INC	23%
Coal	10%
Natural gas	3%
Price sensitive demand	1%
Wind	0%
Oil	0%
Municipal waste	0%
Diesel	0%

Figure 2-6 Day-ahead load-weighted unit markup index: January through June 2010 (See 2009 SOM, Figure 2-6)



Unit Markup Characteristics

Table 2-35 Average, day-ahead marginal unit markup index (By primary fuel and unit type): January through June 2010 (See 2009 SOM, Table 2-41)

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	(0.07)	($2.63)
Diesel	Diesel	(0.24)	($16.12)
Municipal waste	Steam	0.01	$0.23
Natural gas	CT	0.05	$3.45
Natural gas	Diesel	(0.04)	($3.03)
Natural gas	Steam	(0.00)	($0.31)
Oil	Steam	0.01	$1.79
Wind	Wind	0.00	$0.00

Table 2-36 Average, day-ahead marginal unit markup index (By price category): January through June 2010 (See 2009 SOM, Table 2-42)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($2.78)
$25 to $50	(0.06)	($2.41)
$50 to $75	0.01	$0.57
$75 to $100	0.02	$0.30
$100 to $125	0.00	$0.36
$125 to $150	0.19	$25.78
> $150	0.15	$23.68

Markup Component of System Price

Table 2-37 Monthly markup components of day-ahead, load-weighted LMP: January through June 2010 (See 2009 SOM, Table 2-43)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.18)	($0.78)	($1.51)
Feb	($0.86)	($0.61)	($1.11)
Mar	($1.61)	($1.18)	($2.12)
Apr	($1.84)	($1.19)	($2.63)
May	($0.76)	($0.10)	($1.38)
Jun	($0.60)	($0.10)	($1.20)
Annual	($1.12)	($0.65)	($1.61)

Markup Component of Zonal Prices

Table 2-38 Day-ahead, average, zonal markup component: January through June 2010 (See 2009 SOM, Table 2-44)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.93)	($0.42)	($1.47)
AEP	($1.67)	($0.95)	($2.41)
AP	($1.02)	($0.39)	($1.67)
BGE	($0.89)	($0.48)	($1.32)
ComEd	($1.06)	($0.89)	($1.22)
DAY	($1.73)	($0.95)	($2.56)
DLCO	($1.60)	($0.90)	($2.37)
Dominion	($0.91)	($0.79)	($1.04)
DPL	($0.91)	($0.41)	($1.43)
JCPL	($0.94)	($0.43)	($1.50)
Met-Ed	($1.00)	($0.52)	($1.52)
PECO	($0.91)	($0.38)	($1.48)
PENELEC	($1.23)	($0.60)	($1.90)
Pepco	($0.79)	($0.37)	($1.24)
PPL	($0.91)	($0.35)	($1.51)
PSEG	($0.87)	($0.38)	($1.43)
RECO	($0.83)	($0.33)	($1.44)

Markup by System Price Levels

Table 2-39 Average, day-ahead markup (By price category): January through June 2010 (See 2009 SOM, Table 2-45)

	Average Markup Component	Frequency
Below $20	($3.89)	0%
$20 to $40	($2.50)	52%
$40 to $60	($0.47)	37%
$60 to $80	($1.40)	7%
$80 to $100	$1.77	2%
$100 to $120	$1.82	1%
$120 to $140	$10.49	0%
$140 to $160	$0.00	0%
Above $160	$0.00	0%

Markup Component by Fuel, Unit Type

Table 2-40 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through June 2010 (See 2009 SOM, Table 2-46)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.97)	87.0%
Diesel	Diesel	($0.01)	0.6%
Municipal waste	Steam	$0.00	(0.0%)
Natural gas	CT	$0.01	(0.5%)
Natural gas	Diesel	($0.00)	0.3%
Natural gas	Steam	($0.14)	12.4%
Oil	Steam	($0.00)	0.1%
Wind	Wind	$0.00	0.0%
Total		($1.12)	100.0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-41 Frequently mitigated units and associated units (By month): January through June 2010 (See 2009 SOM, Table 2-47)

	FMUs and AUs			Total Eligible for Any Adder
	Tier 1	Tier 2	Tier 3	
January	35	31	27	93
February	35	28	31	94
March	42	16	44	102
April	38	13	47	98
May	35	19	35	89
June	29	16	41	86

Table 2-42 Frequently mitigated units and associated units total months eligible: January through June 2010 (See 2009 SOM, Table 2-48)

Months Adder-Eligible	FMU & AU Count
1	2
2	4
3	16
4	13
5	10
6	67
Total	112

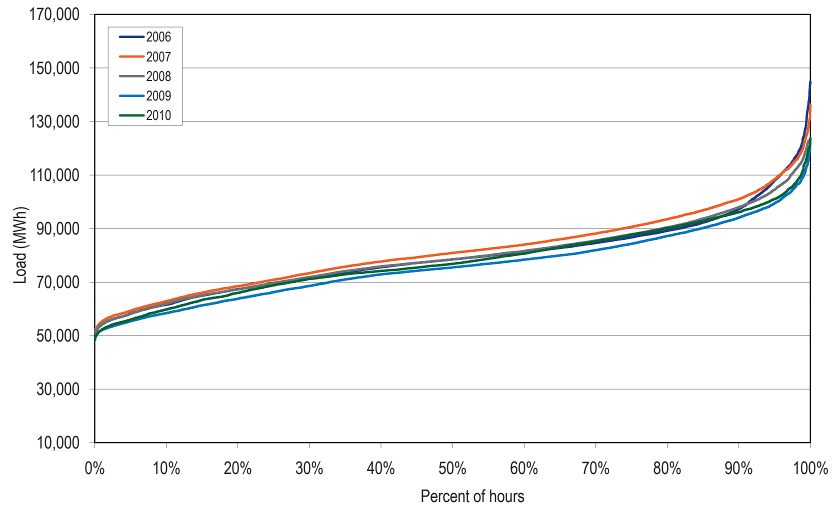
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

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



PJM Real-Time, Annual Average Load

Table 2-43 PJM real-time average load: Calendar years 1998 through June 2010 (See 2009 SOM, Table 2-49)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	76,035	75,471	13,260	(4.4%)	(3.8%)	(3.6%)
2010	78,106	76,831	13,643	2.7%	1.8%	2.9%

PJM Real-Time, Monthly Average Load

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

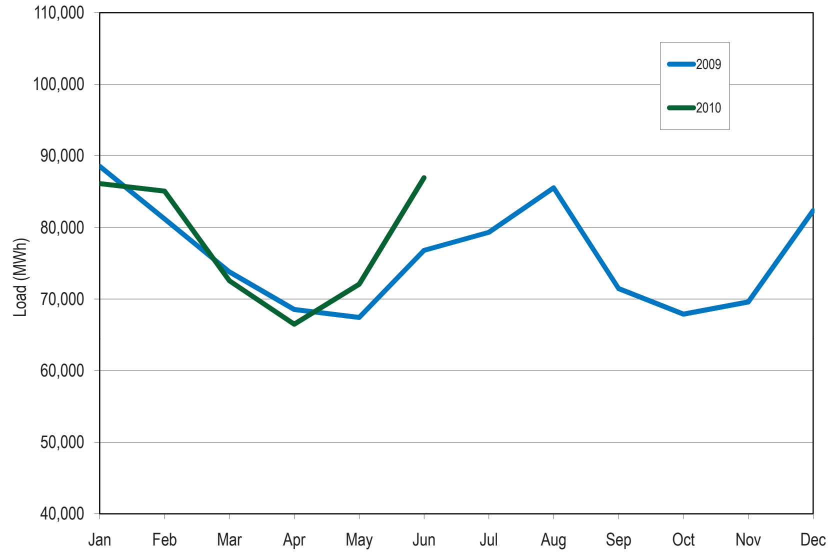


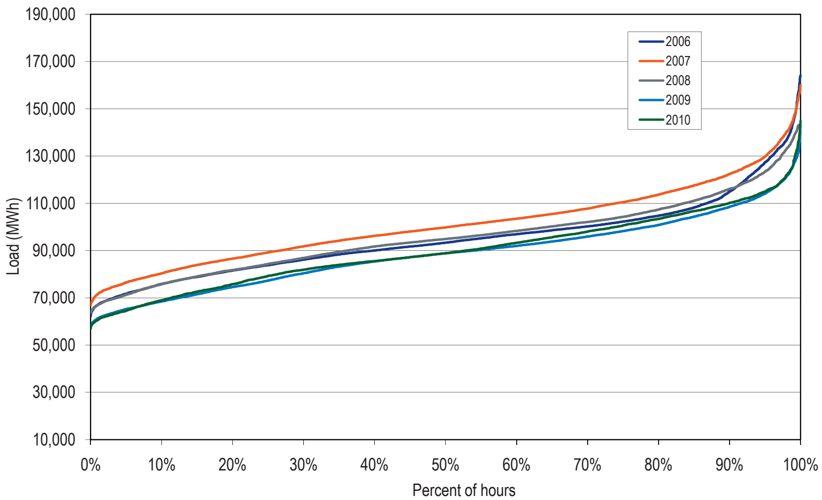
Table 2-44 PJM annual Summer THI, Winter WWP and average temperature: cooling, heating and shoulder months of 2006 through June 2010 (See 2009 SOM, Table 2-51)

	Summer THI	Winter WWP	Shoulder Average Temperature
2006	75.59	31.67	54.62
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	76.14	24.47	56.85

Day-Ahead Load

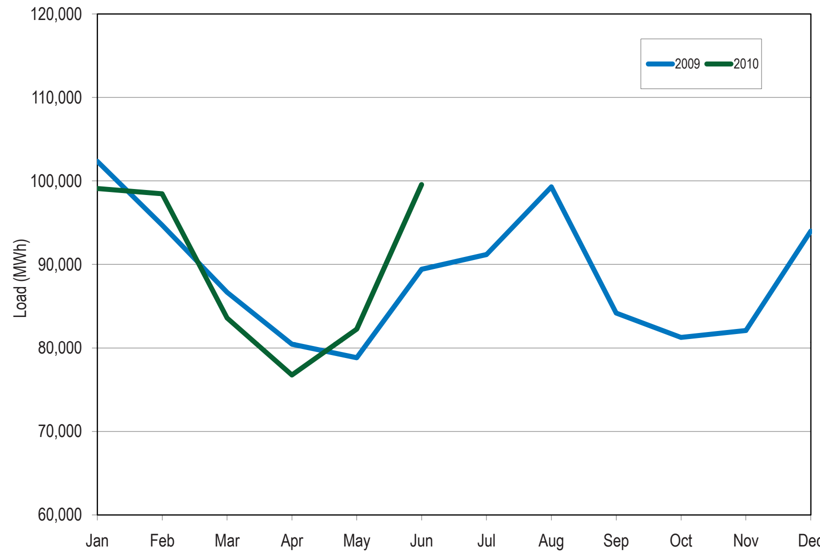
PJM Day-Ahead Load Duration

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



PJM Day-Ahead, Monthly Average Load

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



PJM Day-Ahead, Annual Average Load

Table 2-45 PJM day-ahead average load: Calendar years 2000 through June 2010 (See 2009 SOM, Table 2-52)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	33,045	33,217	6,850	NA	NA	NA
2001	33,318	32,812	6,489	0.8%	(1.2%)	(5.3%)
2002	42,131	40,720	10,130	26.4%	24.1%	56.1%
2003	44,340	44,368	7,883	5.2%	9.0%	(22.2%)
2004	61,034	58,544	16,318	37.7%	32.0%	107.0%
2005	92,002	90,424	17,381	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)
2009	88,707	88,833	14,896	(7.1%)	(6.4%)	(3.5%)
2010	89,830	88,894	15,372	1.3%	0.1%	3.2%

Real-Time and Day-Ahead Load

Table 2-46 Cleared day-ahead and real-time load (MWh): January through June 2010 (See 2009 SOM, Table 2-53)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bid
Average	72,503	1,137	16,191	89,830	78,106	11,724	(4,466)
Median	71,461	1,070	16,186	88,894	76,831	12,062	(4,123)
Standard deviation	12,724	397	2,651	15,372	13,643	1,728	(923)
Peak average	79,529	1,285	17,579	98,393	85,391	13,002	(4,577)
Peak median	78,690	1,196	17,459	97,111	84,389	12,722	(4,737)
Peak standard deviation	10,266	376	2,104	12,231	11,130	1,101	(1,003)
Off peak average	66,325	1,006	14,970	82,301	71,701	10,601	(4,370)
Off peak median	64,862	930	14,817	80,844	70,310	10,534	(4,283)
Off peak standard deviation	11,404	369	2,477	13,834	12,379	1,455	(1,021)

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

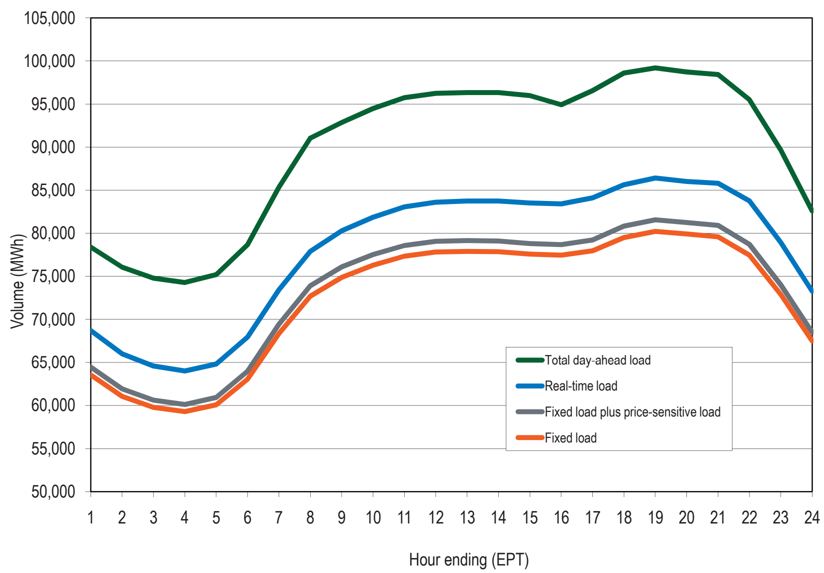
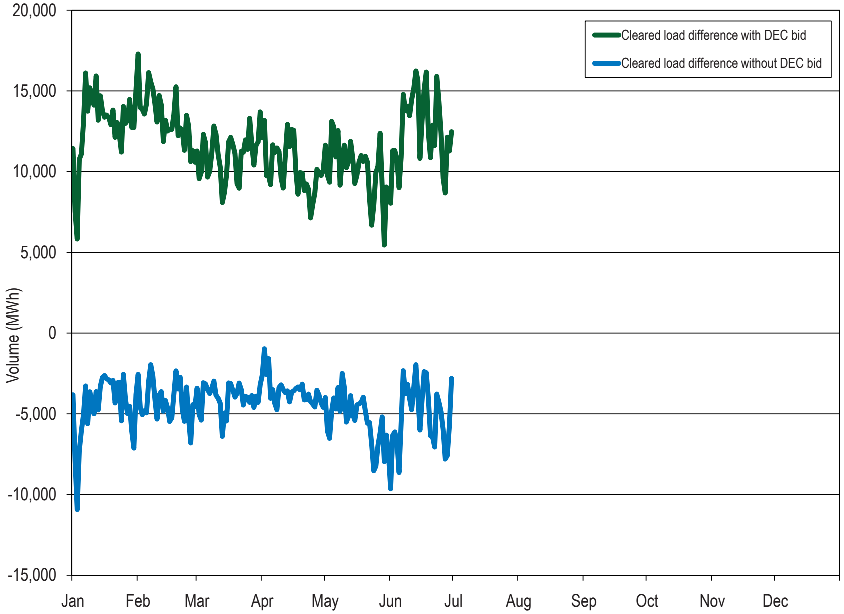


Figure 2-12 Day-ahead and real-time loads (Average daily volumes): January through June 2010 (New Figure)



Day-Ahead and Real-Time Generation

Table 2-47 Day-ahead and real-time generation (MWh): January through June 2010 (See 2009 SOM, Table 2-54)

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	81,523	11,243	92,765	80,702	820	12,063
Median	80,593	11,146	91,802	79,546	1,047	12,256
Standard deviation	14,920	1,656	15,707	13,968	952	1,740
Peak average	89,403	12,160	101,563	88,043	1,360	13,520
Peak median	88,386	12,126	100,311	86,877	1,508	13,434
Peak standard deviation	11,799	1,463	12,454	11,405	394	1,049
Off peak average	74,593	10,436	85,030	74,248	345	10,782
Off peak median	73,299	10,448	83,490	72,645	654	10,845
Off peak standard deviation	13,905	1,372	14,122	12,777	1,127	1,345

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

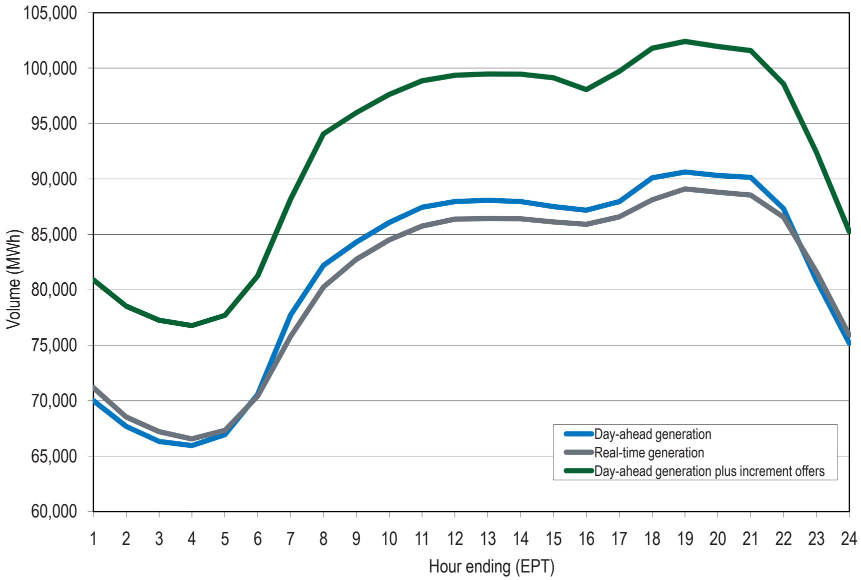
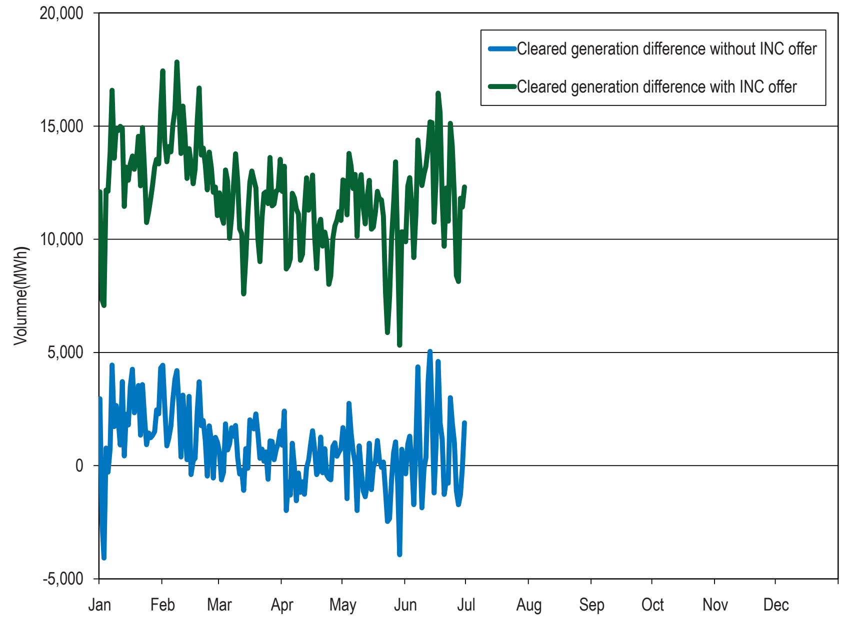


Figure 2-14 Day-ahead and real-time generation (Average daily volumes): January through June 2010 (New Figure)



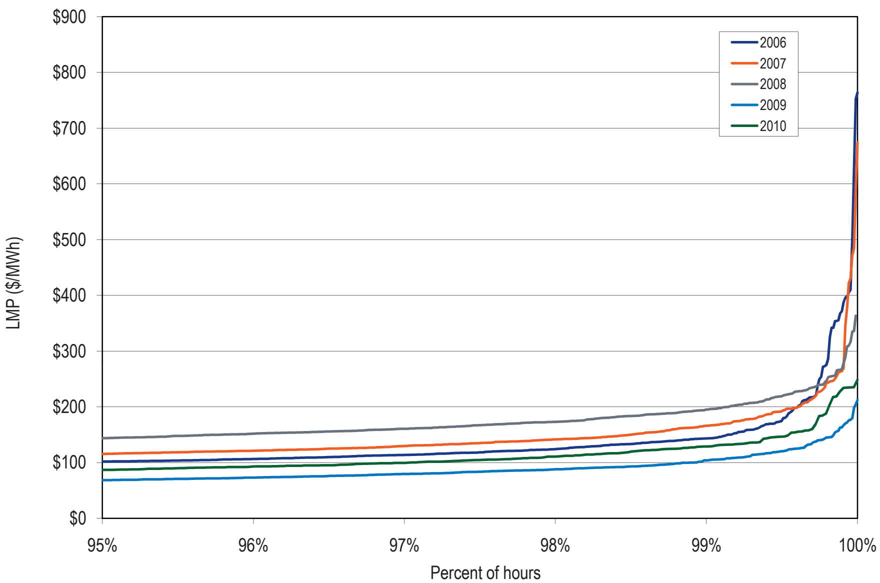
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-15 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2006 through June 2010 (See 2009 SOM, Figure 2-13)



PJM Real-Time, Annual Average LMP

Table 2-48 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 through June 2010 (See 2009 SOM, Table 2-55)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$43.27	$37.11	$22.20	16.7%	13.4%	29.7%

Zonal Real-Time, Annual Average LMP

Table 2-49 Zonal real-time, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-56)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AECO	$44.59	$47.67	$3.08	6.9%
AEP	$36.37	$37.85	$1.48	4.1%
AP	$41.77	$42.65	$0.87	2.1%
BGE	$45.22	$50.08	$4.86	10.8%
ComEd	$30.28	$33.60	$3.32	11.0%
DAY	$35.90	$37.68	$1.78	5.0%
DLCO	$34.49	$37.71	$3.22	9.3%
Dominion	$43.53	$49.34	$5.82	13.4%
DPL	$45.20	$48.14	$2.94	6.5%
JCPL	$44.92	$47.26	$2.34	5.2%
Met-Ed	$43.73	$46.36	$2.62	6.0%
PECO	$43.63	$46.72	$3.08	7.1%
PENELEC	$40.06	$40.77	$0.71	1.8%
Pepco	$44.77	$50.15	$5.39	12.0%
PPL	$43.14	$45.44	$2.30	5.3%
PSEG	$45.44	$48.45	$3.01	6.6%
RECO	$44.22	$46.44	$2.22	5.0%
PJM	$40.12	$43.27	$3.16	7.9%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-50 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-57)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
Delaware	$44.87	$47.44	$2.57	5.7%
Illinois	$30.28	$33.60	$3.32	11.0%
Indiana	$35.71	$36.87	$1.17	3.3%
Kentucky	$36.25	$38.34	$2.10	5.8%
Maryland	$45.20	$49.92	$4.72	10.4%
Michigan	$37.07	$37.45	$0.39	1.0%
New Jersey	$45.16	$47.97	$2.81	6.2%
North Carolina	$42.45	$47.56	$5.11	12.0%
Ohio	$35.69	$37.07	$1.38	3.9%
Pennsylvania	$41.88	$44.00	$2.12	5.1%
Tennessee	$36.34	$39.38	$3.04	8.4%
Virginia	$42.77	$48.06	$5.29	12.4%
West Virginia	$37.65	$38.13	$0.48	1.3%
District of Columbia	$44.92	$50.37	$5.45	12.1%

Hub Real-Time, Annual Average LMP

Table 2-51 Hub real-time, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-58)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AEP Gen Hub	$34.21	$35.37	$1.16	3.4%
AEP-DAY Hub	$35.87	$37.12	$1.24	3.5%
Chicago Gen Hub	$29.44	$32.79	$3.35	11.4%
Chicago Hub	$30.49	$33.77	$3.28	10.8%
Dominion Hub	$42.82	$48.01	$5.19	12.1%
Eastern Hub	$45.06	$48.15	$3.08	6.8%
N Illinois Hub	$30.07	$33.40	$3.33	11.1%
New Jersey Hub	$45.11	$47.86	$2.75	6.1%
Ohio Hub	$35.84	$37.16	$1.32	3.7%
West Interface Hub	$37.20	$40.10	$2.90	7.8%
Western Hub	$41.40	$43.87	$2.47	6.0%

Real-Time, Load-Weighted, Average LMP

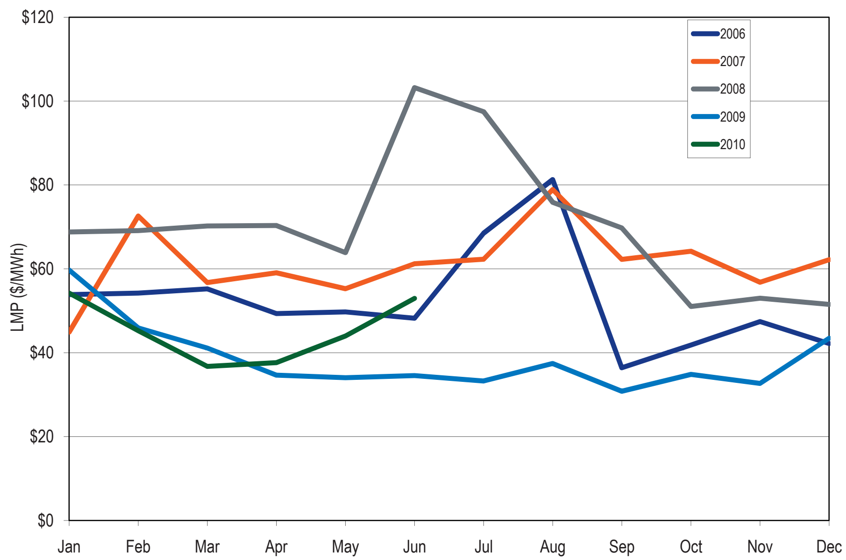
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-52 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through June 2010 (See 2009 SOM, Table 2-59)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$45.75	$38.78	$23.60	17.2%	13.3%	29.6%

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

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



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

Table 2-53 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-60)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AECO	$46.77	$51.21	$4.44	9.5%
AEP	$38.30	$39.53	$1.22	3.2%
AP	$44.59	$44.66	$0.07	0.1%
BGE	$48.39	$53.92	$5.53	11.4%
ComEd	$32.25	$35.48	$3.23	10.0%
DAY	$37.77	$39.50	$1.73	4.6%
DLCO	$35.62	$39.37	$3.75	10.5%
Dominion	$46.89	$53.75	$6.86	14.6%
DPL	$48.77	$51.66	$2.89	5.9%
JCPL	$47.50	$50.97	$3.46	7.3%
Met-Ed	$46.64	$49.02	$2.38	5.1%
PECO	$46.05	$49.58	$3.53	7.7%
PENELEC	$42.08	$42.12	$0.03	0.1%
Pepco	$47.69	$54.16	$6.47	13.6%
PPL	$46.39	$47.93	$1.55	3.3%
PSEG	$47.42	$51.48	$4.06	8.6%
RECO	$46.29	$50.02	$3.72	8.0%
PJM	$42.48	$45.75	$3.27	7.7%

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

Table 2-54 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-61)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
Delaware	$47.92	$50.56	$2.63	5.5%
Illinois	$32.25	$35.48	$3.23	10.0%
Indiana	$37.00	$38.03	$1.03	2.8%
Kentucky	$39.03	$40.64	$1.61	4.1%
Maryland	$48.71	$53.98	$5.27	10.8%
Michigan	$38.50	$39.05	$0.55	1.4%
New Jersey	$47.34	$51.27	$3.93	8.3%
North Carolina	$45.76	$52.03	$6.27	13.7%
Ohio	$37.35	$38.54	$1.19	3.2%
Pennsylvania	$44.33	$46.17	$1.85	4.2%
Tennessee	$38.96	$42.26	$3.29	8.4%
Virginia	$46.17	$52.16	$5.98	13.0%
West Virginia	$40.16	$39.88	($0.28)	(0.7%)
District of Columbia	$46.88	$53.53	$6.65	14.2%

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

Fuel Cost

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

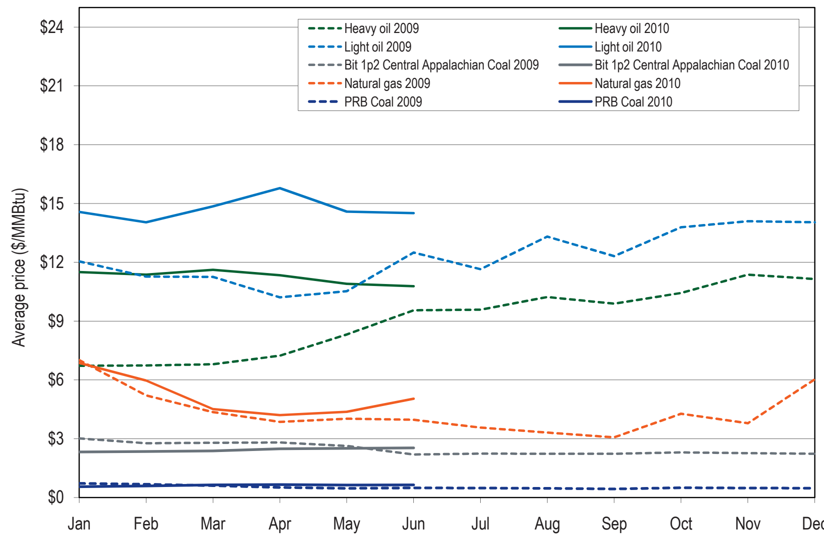


Figure 2-18 Spot average emission price comparison: Calendar years 2009 through June 2010 (See 2009 SOM, Figure 2-16)

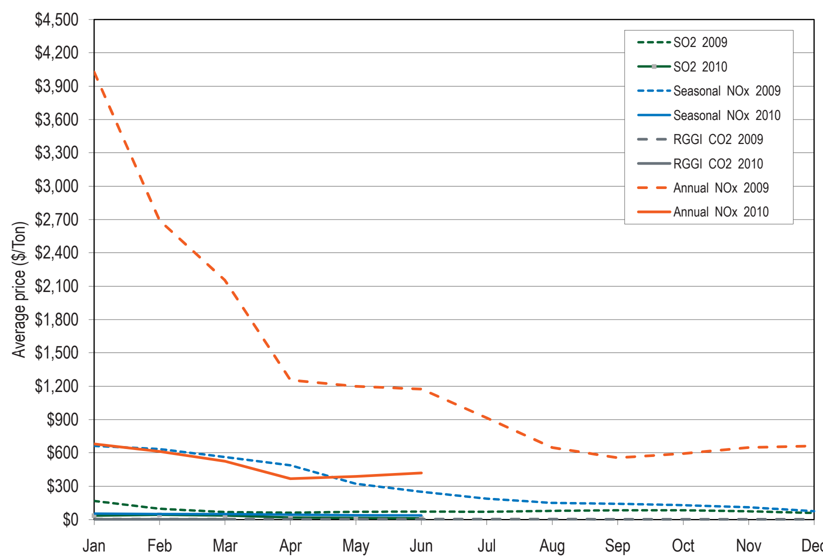


Table 2-55 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2009 SOM, Table 2-62)

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585

Table 2-56 PJM real-time annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-63)

	2010 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$45.75	$49.81	8.9%
	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$42.48	$49.81	17.3%
	2009 Load-Weighted LMP	2010 Load-Weighted LMP	Change
Average	$42.48	$45.75	7.7%

Components of Real-Time, Load-Weighted LMP

Table 2-57 Components of PJM real-time, annual, load-weighted, average LMP: January 1, 2010, through June 30, 2010 (See 2009 SOM, Table 2-64)

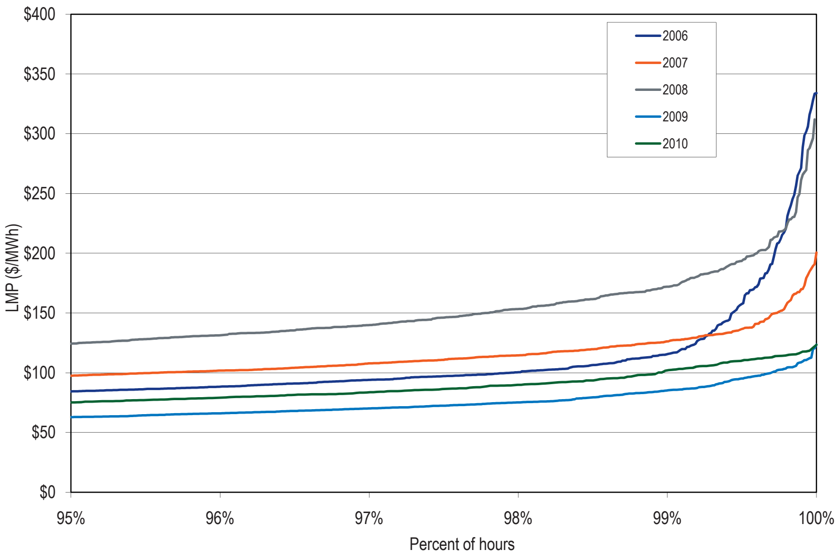
Element	Contribution to LMP	Percent
Coal	$19.61	42.9%
Gas	$18.06	39.5%
10% Cost Adder	$4.28	9.4%
VOM	$2.83	6.2%
NOX	$1.21	2.6%
Oil	$0.90	2.0%
CO2	$0.58	1.3%
Dispatch Differential	$0.33	0.7%
SO2	$0.25	0.6%
FMU Adder	$0.16	0.4%
NA	$0.13	0.3%
M2M Adder	$0.01	0.0%
Shadow Price Limit Adder	$0.01	0.0%
Offline CT Adder	$0.00	0.0%
Municipal Waste	($0.01)	(0.0%)
Markup	($1.15)	(2.5%)
UDS Override Differential	($1.47)	(3.2%)
LMP	$45.75	100.0%

Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-19 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2006 through June 2010 (See 2009 SOM, Figure 2-17)



PJM Day-Ahead, Annual Average LMP

Table 2-58 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 through June 2010 (See 2009 SOM, Table 2-65)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$43.81	$40.64	$15.66	18.4%	15.6%	16.9%

Zonal Day-Ahead, Annual Average LMP

Table 2-59 Zonal day-ahead, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-66)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AECO	$45.38	$48.54	$3.16	7.0%
AEP	$36.19	$38.07	$1.88	5.2%
AP	$41.11	$43.14	$2.03	4.9%
BGE	$46.01	$51.38	$5.37	11.7%
ComEd	$30.42	$34.01	$3.58	11.8%
DAY	$35.34	$37.60	$2.26	6.4%
DLCO	$34.04	$38.37	$4.32	12.7%
Dominion	$44.17	$50.36	$6.19	14.0%
DPL	$45.80	$48.70	$2.90	6.3%
JCPL	$45.58	$48.27	$2.69	5.9%
Met-Ed	$44.24	$47.38	$3.14	7.1%
PECO	$44.67	$47.81	$3.14	7.0%
PENELEC	$40.30	$42.38	$2.08	5.2%
Pepco	$45.60	$51.71	$6.10	13.4%
PPL	$43.82	$46.45	$2.63	6.0%
PSEG	$46.27	$49.27	$3.00	6.5%
RECO	$45.06	$48.07	$3.01	6.7%
PJM	$40.01	$43.81	$3.80	9.5%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-60 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-67)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
Delaware	$45.21	$48.02	$2.81	6.2%
Illinois	$30.42	$34.01	$3.58	11.8%
Indiana	$35.47	$37.01	$1.54	4.3%
Kentucky	$35.95	$38.31	$2.36	6.6%
Maryland	$45.89	$51.14	$5.25	11.4%
Michigan	$36.78	$37.51	$0.73	2.0%
New Jersey	$45.94	$48.88	$2.94	6.4%
North Carolina	$43.03	$48.75	$5.72	13.3%
Ohio	$35.29	$37.04	$1.76	5.0%
Pennsylvania	$42.33	$44.97	$2.64	6.2%
Tennessee	$36.51	$39.64	$3.13	8.6%
Virginia	$43.39	$49.18	$5.79	13.3%
West Virginia	$37.38	$38.47	$1.10	2.9%
District of Columbia	$45.68	$51.92	$6.24	13.7%

Day-Ahead, Load-Weighted, Average LMP

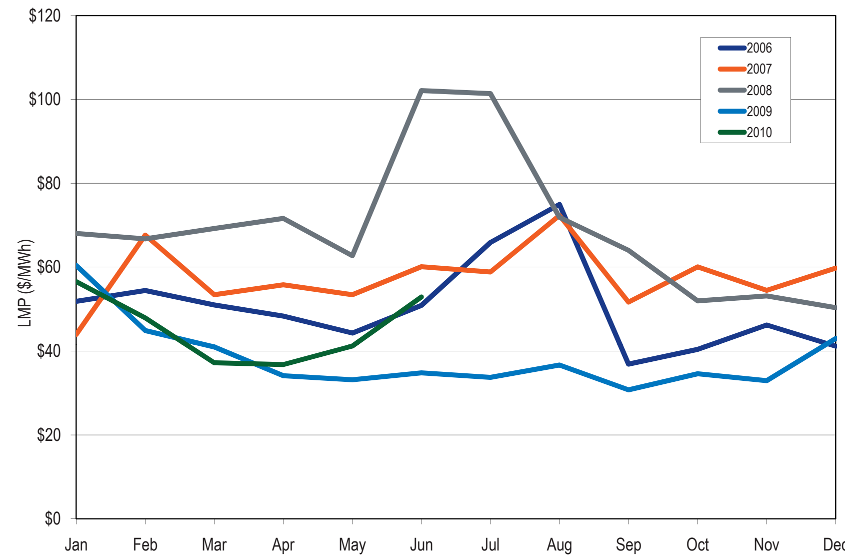
PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-61 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through June 2010 (See 2009 SOM, Table 2-68)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$46.12	$42.50	$16.54	18.8%	15.9%	17.9%

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

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



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-62 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2009 to 2010 (See 2009 SOM, Table 2-69)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
AECO	$48.09	$52.63	$4.54	9.4%
AEP	$37.95	$39.68	$1.73	4.6%
AP	$43.83	$45.14	$1.31	3.0%
BGE	$49.12	$55.13	$6.01	12.2%
ComEd	$31.72	$35.49	$3.77	11.9%
DAY	$36.99	$39.30	$2.31	6.2%
DLCO	$35.10	$40.16	$5.06	14.4%
Dominion	$47.39	$54.80	$7.41	15.6%
DPL	$48.86	$52.03	$3.17	6.5%
JCPL	$47.94	$51.29	$3.35	7.0%
Met-Ed	$47.29	$49.92	$2.63	5.6%
PECO	$47.08	$50.48	$3.40	7.2%
PENELEC	$42.35	$43.66	$1.31	3.1%
Pepco	$48.20	$54.53	$6.33	13.1%
PPL	$46.72	$48.88	$2.16	4.6%
PSEG	$48.45	$51.91	$3.46	7.1%
RECO	$47.59	$51.58	$3.99	8.4%
PJM	$42.21	$46.12	$3.91	9.3%

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

Table 2-63 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-70)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Difference	Difference as Percent of 2009
Delaware	$48.05	$51.06	$3.02	6.3%
Illinois	$31.72	$35.49	$3.77	11.9%
Indiana	$36.72	$38.35	$1.63	4.5%
Kentucky	$38.34	$40.18	$1.84	4.8%
Maryland	$49.12	$54.56	$5.43	11.1%
Michigan	$37.93	$38.81	$0.89	2.3%
New Jersey	$48.22	$51.80	$3.57	7.4%
North Carolina	$46.44	$52.99	$6.55	14.1%
Ohio	$36.89	$38.46	$1.57	4.3%
Pennsylvania	$44.69	$46.95	$2.25	5.0%
Tennessee	$38.72	$42.08	$3.36	8.7%
Virginia	$46.51	$53.23	$6.72	14.4%
West Virginia	$39.63	$40.20	$0.56	1.4%
District of Columbia	$47.70	$54.37	$6.67	14.0%

Components of Day-Ahead, Load-Weighted LMP

Table 2-64 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-71)

Element	Contribution to LMP	Percent
INC	$17.41	37.7%
DEC	$11.91	25.8%
Coal	$7.05	15.3%
Natural gas	$5.79	12.6%
Price sensitive demand	$1.56	3.4%
10% Cost offer	$1.45	3.1%
VOM	$0.85	1.8%
Transaction	$0.50	1.1%
NOx	$0.39	0.8%
CO2	$0.19	0.4%
Oil	$0.10	0.2%
SO2	$0.09	0.2%
Diesel	$0.02	0.0%
Constrained off	$0.00	0.0%
FMU adder	$0.00	0.0%
Markup	($1.12)	(2.4%)
NA	($0.08)	(0.2%)
Total	$46.12	100.0%

Marginal Losses

Table 2-65 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through June 2010 (See 2009 SOM, Table 2-72)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$43.27	$43.18	$0.05	$0.04

Table 2-66 Zonal real-time, simple average LMP components (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-73)

	2009 (Jan - Jun)				2010 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$44.59	$40.04	$2.60	$1.95	$47.67	$43.18	$2.24	$2.25
AEP	$36.37	$40.04	($2.38)	($1.28)	$37.85	$43.18	($3.81)	($1.52)
AP	$41.77	$40.04	$1.79	($0.05)	$42.65	$43.18	($0.37)	($0.17)
BGE	$45.22	$40.04	$3.49	$1.69	$50.08	$43.18	$4.72	$2.18
ComEd	$30.28	$40.04	($7.26)	($2.50)	$33.60	$43.18	($6.74)	($2.84)
DAY	$35.90	$40.04	($3.22)	($0.92)	$37.68	$43.18	($4.52)	($0.98)
DLCO	$34.49	$40.04	($4.12)	($1.43)	$37.71	$43.18	($3.88)	($1.59)
Dominion	$43.53	$40.04	$2.90	$0.59	$49.34	$43.18	$5.35	$0.81
DPL	$45.20	$40.04	$3.02	$2.14	$48.14	$43.18	$2.52	$2.44
JCPL	$44.92	$40.04	$2.72	$2.17	$47.26	$43.18	$1.79	$2.29
Met-Ed	$43.73	$40.04	$2.70	$1.00	$46.36	$43.18	$2.04	$1.13
PECO	$43.63	$40.04	$2.19	$1.41	$46.72	$43.18	$1.92	$1.61
PENELEC	$40.06	$40.04	$0.09	($0.07)	$40.77	$43.18	($2.13)	($0.29)
Pepco	$44.77	$40.04	$3.60	$1.13	$50.15	$43.18	$5.57	$1.41
PPL	$43.14	$40.04	$2.29	$0.81	$45.44	$43.18	$1.36	$0.90
PSEG	$45.44	$40.04	$3.17	$2.23	$48.45	$43.18	$2.96	$2.31
RECO	$44.22	$40.04	$2.21	$1.98	$46.44	$43.18	$1.25	$2.00

Table 2-67 Hub real-time, simple average LMP components (Dollars per MWh): January through June 2010 (See 2009 SOM, 2-74)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.37	$43.18	($4.86)	($2.95)
AEP-DAY Hub	$37.12	$43.18	($4.34)	($1.73)
Chicago Gen Hub	$32.79	$43.18	($7.00)	($3.38)
Chicago Hub	$33.77	$43.18	($6.59)	($2.82)
Dominion Hub	$48.01	$43.18	$4.52	$0.30
Eastern Hub	$48.15	$43.18	$2.35	$2.62
N Illinois Hub	$33.40	$43.18	($6.73)	($3.05)
New Jersey Hub	$47.86	$43.18	$2.43	$2.25
Ohio Hub	$37.16	$43.18	($4.34)	($1.68)
West Interface Hub	$40.10	$43.18	($1.68)	($1.40)
Western Hub	$43.87	$43.18	$0.93	($0.25)

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

Table 2-68 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-75)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$51.21	$46.08	$2.71	$2.42
AEP	$39.53	$45.29	($4.18)	($1.59)
AP	$44.66	$45.45	($0.60)	($0.19)
BGE	$53.92	$46.03	$5.54	$2.35
ComEd	$35.48	$45.16	($6.79)	($2.89)
DAY	$39.50	$45.49	($5.02)	($0.97)
DLCO	$39.37	$45.19	($4.13)	($1.69)
Dominion	$53.75	$46.37	$6.49	$0.89
DPL	$51.66	$46.29	$2.71	$2.66
JCPL	$50.97	$46.35	$2.16	$2.45
Met-Ed	$49.02	$45.56	$2.27	$1.19
PECO	$49.58	$45.71	$2.18	$1.69
PENELEC	$42.12	$44.90	($2.45)	($0.33)
Pepco	$54.16	$46.11	$6.55	$1.50
PPL	$47.93	$45.52	$1.48	$0.94
PSEG	$51.48	$45.73	$3.33	$2.42
RECO	$50.02	$46.27	$1.62	$2.13
PJM	$45.75	$45.65	$0.06	$0.04

Table 2-69 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 through June 2010 (See 2009 SOM, Table 2-76)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)
2010	$43.81	$43.74	$0.07	$0.00

Table 2-70 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through June 2009 and 2010 (See 2009 SOM, Table 2-77)

	2009 (Jan - Jun)				2010 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$45.38	$40.27	$2.61	$2.49	$48.54	$43.74	$2.14	$2.66
AEP	$36.19	$40.27	($2.41)	($1.67)	$38.07	$43.74	($3.52)	($2.16)
AP	$41.11	$40.27	$0.75	$0.08	$43.14	$43.74	($0.45)	($0.16)
BGE	$46.01	$40.27	$3.72	$2.02	$51.38	$43.74	$4.75	$2.89
ComEd	$30.42	$40.27	($6.40)	($3.45)	$34.01	$43.74	($5.95)	($3.78)
DAY	$35.34	$40.27	($3.37)	($1.57)	$37.60	$43.74	($4.25)	($1.89)
DLCO	$34.04	$40.27	($4.56)	($1.68)	$38.37	$43.74	($3.47)	($1.91)
Dominion	$44.17	$40.27	$2.93	$0.96	$50.36	$43.74	$5.20	$1.42
DPL	$45.80	$40.27	$2.92	$2.61	$48.70	$43.74	$2.26	$2.70
JCPL	$45.58	$40.27	$2.51	$2.80	$48.27	$43.74	$1.56	$2.97
Met-Ed	$44.24	$40.27	$2.69	$1.28	$47.38	$43.74	$2.22	$1.42
PECO	$44.67	$40.27	$2.43	$1.97	$47.81	$43.74	$1.87	$2.20
PENELEC	$40.30	$40.27	($0.01)	$0.04	$42.38	$43.74	($1.50)	$0.14
Pepco	$45.60	$40.27	$3.67	$1.66	$51.71	$43.74	$5.75	$2.21
PPL	$43.82	$40.27	$2.46	$1.09	$46.45	$43.74	$1.58	$1.12
PSEG	$46.27	$40.27	$2.99	$3.00	$49.27	$43.74	$2.34	$3.18
RECO	$45.06	$40.27	$2.06	$2.72	$48.07	$43.74	$1.52	$2.80

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

Table 2-71 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-78)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$52.63	$47.19	$2.46	$2.97
AEP	$39.68	$45.85	($3.91)	($2.26)
AP	$45.14	$45.99	($0.67)	($0.18)
BGE	$55.13	$46.52	$5.49	$3.12
ComEd	$35.49	$45.44	($6.06)	($3.88)
DAY	$39.30	$46.01	($4.75)	($1.95)
DLCO	$40.16	$45.78	($3.61)	($2.01)
Dominion	$54.80	$46.85	$6.41	$1.54
DPL	$52.03	$46.72	$2.41	$2.90
JCPL	$51.29	$46.46	$1.67	$3.16
Met-Ed	$49.92	$46.02	$2.42	$1.49
PECO	$50.48	$46.18	$1.99	$2.32
PENELEC	$43.66	$45.25	($1.70)	$0.11
Pepco	$54.53	$45.82	$6.37	$2.33
PPL	$48.88	$46.01	$1.68	$1.18
PSEG	$51.91	$46.09	$2.48	$3.34
RECO	$51.58	$46.90	$1.67	$3.01
PJM	$46.12	$46.04	$0.08	($0.00)

Marginal Loss Accounting

Monthly Marginal Loss Costs

Table 2-72 Marginal loss costs by type (Dollars (Millions)): January through June 2010 (See 2009 SOM, Table 2-79)

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$45.5	($136.3)	$7.0	$188.9	$1.2	($2.8)	($4.0)	$0.0	$188.9
Feb	$31.6	($100.1)	$3.0	$134.7	$0.4	($0.6)	($1.3)	($0.4)	$134.3
Mar	$21.0	($70.5)	$2.7	$94.2	$0.2	($0.2)	($1.2)	($0.8)	$93.4
Apr	$16.8	($59.9)	$3.8	$80.4	($0.2)	$0.1	($1.7)	($2.0)	$78.4
May	$17.6	($77.6)	$6.0	$101.2	$0.4	($1.3)	($3.3)	($1.6)	$99.6
Jun	$20.3	($127.4)	$10.8	$158.5	$3.2	($0.3)	($5.8)	($2.3)	$156.3
Total	$152.7	($571.8)	$33.5	$757.9	$5.2	($5.1)	($17.3)	($7.0)	$750.9

Zonal Marginal Loss Costs

Table 2-73 Marginal loss costs by control zone and type (Dollars (Millions)): January through June 2010 (See 2009 SOM, Table 2-80)

	Marginal Loss Costs by Control Zone (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$14.3	$3.6	$0.1	$10.8	$1.0	($0.2)	($0.0)	$1.2	$11.9
AEP	($35.7)	($171.8)	$10.7	$146.9	($1.4)	$1.7	($1.4)	($4.5)	$142.3
AP	($3.0)	($60.0)	$6.0	$63.0	$1.6	$2.7	($3.7)	($4.9)	$58.1
BGE	$42.5	$13.4	$2.1	$31.2	$2.9	($2.0)	($1.7)	$3.3	$34.5
ComEd	($107.0)	($244.6)	$0.9	$138.6	($2.1)	($1.1)	($1.1)	($2.0)	$136.5
DAY	($2.8)	($32.2)	$4.7	$34.1	($0.0)	$1.0	($4.1)	($5.1)	$29.0
DLCO	($20.4)	($32.4)	$0.1	$12.2	($1.3)	($0.3)	($0.1)	($1.0)	$11.1
Dominion	$61.2	($20.4)	$3.9	$85.4	$1.6	($0.6)	($1.9)	$0.3	$85.7
DPL	$27.4	$4.7	$0.4	$23.2	($1.0)	($0.7)	($0.3)	($0.5)	$22.7
JCPL	$35.1	$11.9	$0.2	$23.4	$0.4	($0.7)	($0.2)	$1.0	$24.4
Met-Ed	$11.8	$1.7	$0.1	$10.1	$0.0	($0.2)	($0.1)	$0.2	$10.3
PECO	$33.7	$11.6	$0.0	$22.1	($0.2)	($0.9)	($0.0)	$0.7	$22.8
PENELEC	($11.4)	($46.0)	$0.0	$34.5	$2.4	($2.2)	$0.1	$4.6	$39.2
Pepco	$61.9	$29.0	$2.3	$35.1	($1.9)	($0.4)	($1.6)	($3.1)	$32.0
PJM	($37.5)	($53.7)	($5.7)	$10.6	$2.2	($5.8)	$4.4	$12.4	$22.9
PPL	$23.3	($5.0)	$0.9	$29.1	$1.0	$0.5	($0.0)	$0.5	$29.6
PSEG	$57.5	$18.2	$6.8	$46.1	($0.4)	$4.4	($5.6)	($10.4)	$35.7
RECO	$2.0	$0.3	$0.0	$1.7	$0.2	($0.2)	($0.0)	$0.4	$2.1
Total	$152.7	($571.8)	$33.5	$757.9	$5.2	($5.1)	($17.3)	($7.0)	$750.9

Table 2-74 Monthly marginal loss costs by control zone (Dollars (Millions)): January through June 2010 (See 2009 SOM, Table 2-81)

	Marginal Loss Costs by Control Zone (Millions)						
	Jan	Feb	Mar	Apr	May	Jun	Grand Total
AECO	$2.6	$1.5	$1.4	$1.4	$1.6	$3.3	$11.9
AEP	$40.0	$25.9	$16.4	$13.8	$14.8	$31.5	$142.3
AP	$13.7	$11.2	$6.8	$6.5	$8.4	$11.3	$58.1
BGE	$8.8	$6.7	$3.7	$3.3	$4.8	$7.3	$34.5
ComEd	$36.1	$23.9	$19.8	$16.2	$16.9	$23.7	$136.5
DAY	$6.6	$5.3	$4.2	$2.6	$4.6	$5.6	$29.0
DLCO	$3.0	$2.3	$1.6	$1.3	$1.4	$1.5	$11.1
Dominion	$20.1	$15.9	$9.0	$8.9	$10.8	$21.0	$85.7
DPL	$5.7	$3.6	$2.6	$2.8	$3.2	$4.7	$22.7
JCPL	$6.3	$4.0	$3.3	$2.3	$3.3	$5.1	$24.4
Met-Ed	$2.8	$1.6	$1.4	$1.0	$1.4	$2.1	$10.3
PECO	$4.2	$3.7	$2.3	$1.9	$3.6	$7.1	$22.8
PENELEC	$10.4	$7.2	$3.6	$3.6	$5.8	$8.6	$39.2
Pepco	$6.7	$5.7	$4.5	$3.8	$5.0	$6.4	$32.0
PJM	$5.5	$3.7	$2.9	$2.4	$5.2	$3.2	$22.9
PPL	$8.8	$6.3	$3.7	$2.2	$3.2	$5.4	$29.6
PSEG	$7.0	$5.4	$5.8	$4.3	$5.3	$7.9	$35.7
RECO	$0.5	$0.2	$0.2	$0.2	$0.3	$0.5	$2.1
Total	$188.9	$134.3	$93.4	$78.4	$99.6	$156.3	$750.9

Virtual Offers and Bids

Table 2-75 Monthly volume of cleared and submitted INCs, DECs: January through June 2010 (See 2009 SOM, Table 2-82)

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	11,144	21,634	282	936	17,513	29,406	266	893
Feb	12,387	23,827	387	1,122	17,602	28,542	270	883
Mar	10,811	21,062	308	915	15,019	24,968	253	763
Apr	10,512	19,940	289	784	13,875	24,458	246	705
May	11,165	19,744	218	806	15,556	25,194	223	787
Jun	11,534	22,956	254	1,496	17,689	27,422	258	1,246
Jul								
Aug								
Sep								
Oct								
Nov								
Dec								
Annual	11,243	21,490	288	1,006	16,191	26,642	252	879

Table 2-76 Type of day-ahead marginal units: January through June 2010 (See 2009 SOM, Table 2-83)

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	16.5%	30.9%	32.5%	19.4%	0.7%
Feb	14.9%	34.1%	24.3%	26.1%	0.6%
Mar	10.6%	29.9%	34.1%	24.7%	0.7%
Apr	11.5%	32.9%	32.8%	22.5%	0.3%
May	12.3%	36.0%	28.6%	22.5%	0.6%
Jun	14.1%	35.2%	27.8%	22.5%	0.5%
Annual	13.3%	33.1%	30.1%	22.9%	0.6%

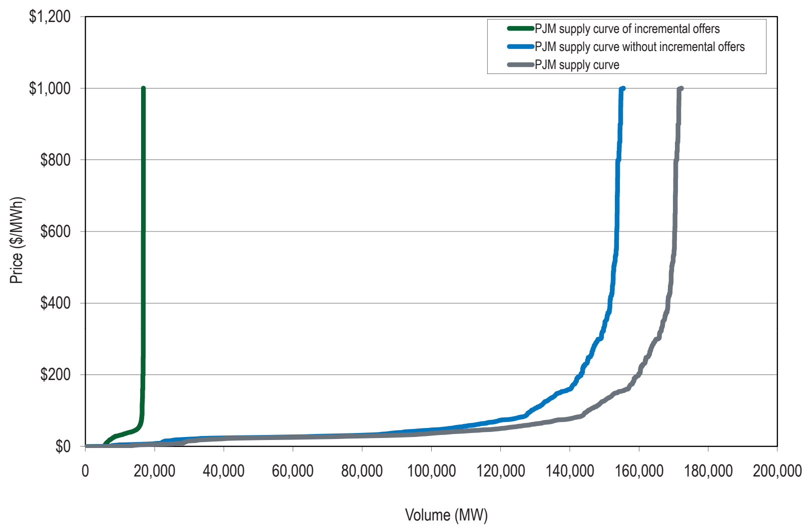
Table 2-77 PJM virtual bids by type of bid parent organization (MW): January through June 2010 (See 2009 SOM, Table 2-84)

	Category	Total Virtual Bids MW	Percentage
2010	Financial	60,824,903	29.1%
2010	Physical	148,212,716	70.9%
2010	Total	209,037,618	100%

Table 2-78 PJM virtual bids by top ten locations (MW): January through June 2010 (See 2009 SOM, Table 2-85)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	30,997,867.3	38,042,351.1	69,040,218.4
N ILLINOIS HUB	HUB	4,946,101.1	5,334,212.4	10,280,313.5
AEP-DAYTON HUB	HUB	2,927,074.9	3,726,855.4	6,653,930.3
PSEG	ZONE	1,397,499.8	3,468,094.5	4,865,594.3
Pepco	ZONE	3,505,342.4	820,900.3	4,326,242.7
PPL	ZONE	242,258.5	3,935,110.3	4,177,368.8
BGE	ZONE	2,125,414.0	1,729,223.7	3,854,637.7
JCPL	ZONE	2,273,216.3	1,562,999.4	3,836,215.7
MISO	INTERFACE	727,823.2	1,505,247.1	2,233,070.3
IMO	INTERFACE	1,483,146.6	615,369.3	2,098,515.9

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



Price Convergence

Table 2-79 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-86)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$43.81	$43.27	($0.54)	(1.2%)
Median	$40.64	$37.11	($3.53)	(9.5%)
Standard deviation	$15.66	$22.20	$6.54	29.5%

Table 2-80 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 through June 2010 (See 2009 SOM, Table 2-87)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$31.97	$30.36	($1.61)	(5.3%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.0%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$43.81	$43.27	($0.54)	(1.2%)

Table 2-81 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2006 through June 2010 (See 2009 SOM, Table 2-88)

	2006		2007		2008		2009		2010	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	1	0.01%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	1	0.02%	0	0.00%	1	0.01%	0	0.00%	0	0.00%
($100) to ($50)	9	0.13%	33	0.38%	88	1.01%	3	0.03%	6	0.14%
($50) to $0	5,205	59.54%	4,600	52.89%	5,120	59.30%	5,108	58.34%	2,890	66.68%
$0 to $50	3,372	98.04%	3,827	96.58%	3,247	96.27%	3,603	99.47%	1,366	98.13%
$50 to $100	152	99.77%	255	99.49%	284	99.50%	41	99.94%	69	99.72%
$100 to $150	9	99.87%	31	99.84%	37	99.92%	5	100.00%	5	99.84%
$150 to $200	4	99.92%	5	99.90%	4	99.97%	0	100.00%	7	100.00%
$200 to $250	1	99.93%	1	99.91%	2	99.99%	0	100.00%	0	100.00%
$250 to $300	3	99.97%	3	99.94%	0	99.99%	0	100.00%	0	100.00%
$300 to $350	0	99.97%	2	99.97%	1	100.00%	0	100.00%	0	100.00%
$350 to $400	1	99.98%	1	99.98%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	99.98%	1	99.99%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	1	99.99%	1	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-22 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through June 2010 (See 2009 SOM, Figure 2-20)

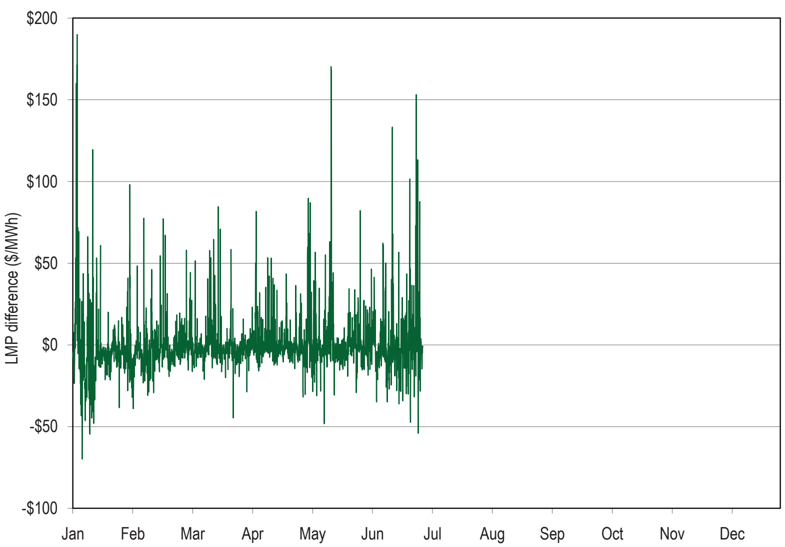


Figure 2-23 Monthly simple average of real-time minus day-ahead LMP: January through June 2010 (See 2009 SOM, Figure 2-21)

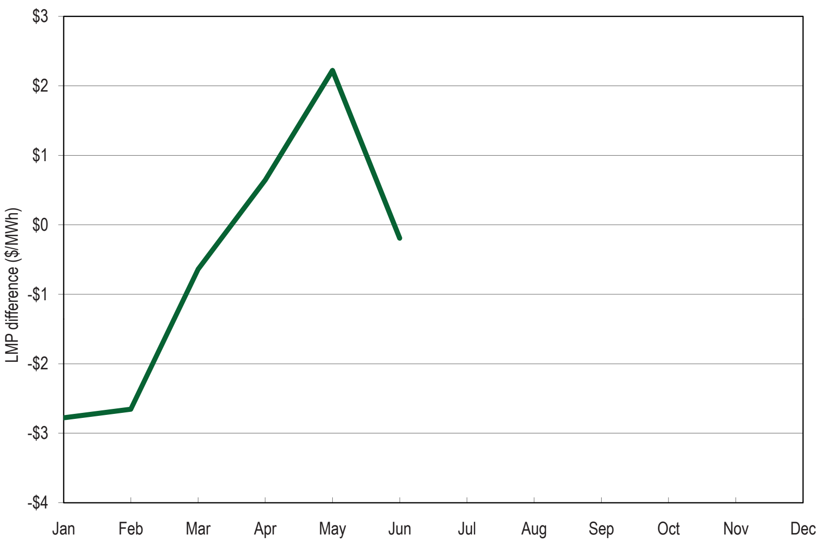
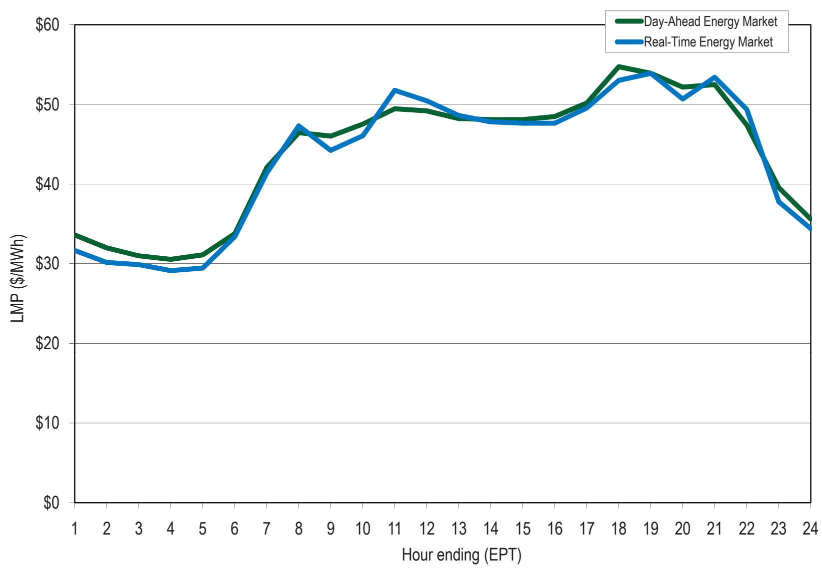


Figure 2-24 PJM system simple hourly average LMP: January through June 2010 (See 2009 SOM, Figure 2-22)



Zonal Price Convergence

Table 2-82 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-89)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$48.54	$47.67	($0.87)	(1.8%)
AEP	$38.07	$37.85	($0.22)	(0.6%)
AP	$43.14	$42.65	($0.50)	(1.2%)
BGE	$51.38	$50.08	($1.30)	(2.6%)
ComEd	$34.01	$33.60	($0.41)	(1.2%)
DAY	$37.60	$37.68	$0.08	0.2%
DLCO	$38.37	$37.71	($0.66)	(1.7%)
Dominion	$50.36	$49.34	($1.02)	(2.1%)
DPL	$48.70	$48.14	($0.56)	(1.2%)
JCPL	$48.27	$47.26	($1.01)	(2.1%)
Met-Ed	$47.38	$46.36	($1.03)	(2.2%)
PECO	$47.81	$46.72	($1.10)	(2.3%)
PENELEC	$42.38	$40.77	($1.61)	(3.9%)
Pepco	$51.71	$50.15	($1.55)	(3.1%)
PPL	$46.45	$45.44	($1.01)	(2.2%)
PSEG	$49.27	$48.45	($0.82)	(1.7%)
RECO	$48.07	$46.44	($1.63)	(3.5%)

Price Convergence by Jurisdiction

Table 2-83 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through June 2010 (See 2009 SOM, Table 2-90)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$48.02	$47.44	($0.58)	(1.2%)
Illinois	$34.01	$33.60	($0.41)	(1.2%)
Indiana	$37.01	$36.87	($0.14)	(0.4%)
Kentucky	$38.31	$38.34	$0.03	0.1%
Maryland	$51.14	$49.92	($1.22)	(2.4%)
Michigan	$37.51	$37.45	($0.06)	(0.2%)
New Jersey	$48.88	$47.97	($0.91)	(1.9%)
North Carolina	$48.75	$47.56	($1.19)	(2.5%)
Ohio	$37.04	$37.07	$0.03	0.1%
Pennsylvania	$44.97	$44.00	($0.98)	(2.2%)
Tennessee	$39.64	$39.38	($0.26)	(0.7%)
Virginia	$49.18	$48.06	($1.13)	(2.3%)
West Virginia	$38.47	$38.13	($0.35)	(0.9%)
District of Columbia	$51.92	$50.37	($1.55)	(3.1%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-84 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2009 to June 30, 2010 (See 2009 SOM, Table 2-91)

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.6%	15.4%	72.0%	11.9%	17.4%	70.7%	(0.7%)	2.0%	(1.3%)
Feb	13.4%	14.5%	72.1%	13.3%	18.1%	68.6%	(0.1%)	3.6%	(3.5%)
Mar	13.8%	16.7%	69.5%	12.7%	18.2%	69.1%	(1.0%)	1.5%	(0.4%)
Apr	13.5%	17.2%	69.3%	12.5%	19.2%	68.2%	(0.9%)	2.0%	(1.1%)
May	14.6%	18.8%	66.7%	11.5%	19.9%	68.6%	(3.1%)	1.1%	2.0%
Jun	12.5%	16.5%	71.0%	10.4%	19.0%	70.6%	(2.1%)	2.5%	(0.4%)
Jul	12.6%	16.9%	70.5%						
Aug	11.7%	16.0%	72.3%						
Sep	12.5%	18.1%	69.4%						
Oct	13.0%	19.8%	67.2%						
Nov	13.2%	19.0%	67.8%						
Dec	11.7%	16.8%	71.5%						
Annual	12.9%	17.0%	70.1%	12.0%	18.6%	69.4%	(0.8%)	1.6%	(0.7%)

Day-Ahead Load and Spot Market

Table 2-85 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2009 to June 30, 2010 (See 2009 SOM, Table 2-92)

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.4%	13.7%	81.9%	4.5%	17.8%	77.7%	0.1%	4.1%	(4.2%)
Feb	4.5%	12.3%	83.2%	4.5%	18.4%	77.1%	0.0%	6.0%	(6.1%)
Mar	4.3%	12.8%	82.9%	4.7%	18.4%	76.9%	0.3%	5.7%	(6.0%)
Apr	4.4%	13.8%	81.7%	4.8%	19.1%	76.1%	0.4%	5.3%	(5.6%)
May	4.6%	15.6%	79.8%	6.5%	19.0%	74.5%	1.9%	3.4%	(5.3%)
Jun	4.7%	13.9%	81.4%	4.6%	18.6%	76.8%	(0.1%)	4.7%	(4.7%)
Jul	5.6%	16.0%	78.4%						
Aug	5.2%	15.3%	79.5%						
Sep	4.8%	16.1%	79.2%						
Oct	5.0%	17.8%	77.2%						
Nov	5.8%	15.9%	78.3%						
Dec	5.2%	15.6%	79.2%						
Annual	4.9%	14.9%	80.2%	4.9%	18.5%	76.6%	0.0%	3.6%	(3.7%)

Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-86 Overview of Demand Side Programs (See 2009 SOM, Table 2-93)

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

Participation

Economic Program

Table 2-87 Economic Program registration on peak load days: Calendar years 2002 to 2009 and January through June 2010 (See 2009 SOM, Table 2-94)

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
03-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
02-Aug-06	253	1,100.7
08-Aug-07	2,897	2,498.0
09-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
23-Jun-10	727	1,891.5

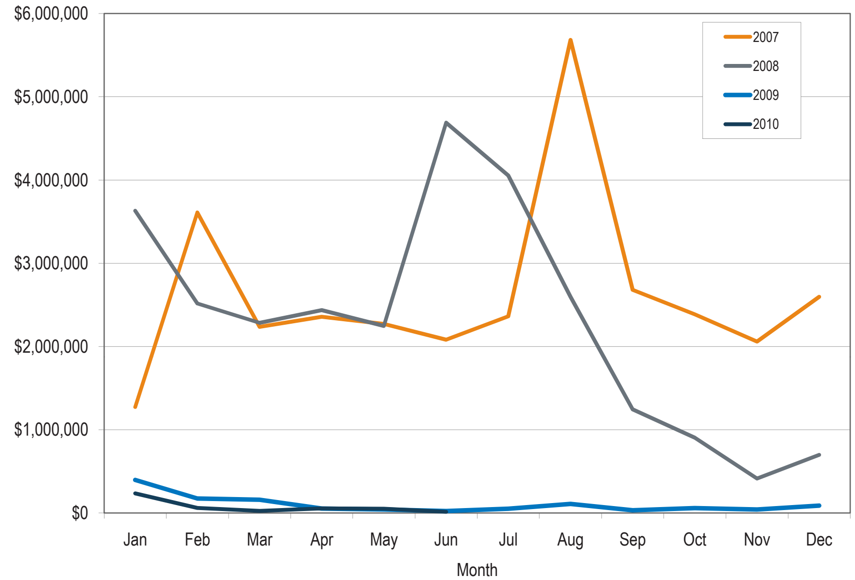
Table 2-88 Economic Program registrations on the last day of the month: January 2007 through June 2010 (See 2009 SOM, Table 2-95)

	2007		2008		2009		2010	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303	1,841	2,623
Feb	953	1,567	4,902	2,961	4,869	3,219	1,842	2,624
Mar	959	1,578	4,972	3,012	4,867	3,227	1,845	2,623
Apr	980	1,648	5,016	3,197	2,582	3,242	1,849	2,016
May	996	3,674	5,069	3,588	1,250	2,860	1,875	2,045
Jun	2,490	2,168	3,112	3,014	1,265	2,461	813	1,025
Jul	2,872	2,459	4,542	3,165	1,265	2,445		
Aug	2,911	2,582	4,815	3,232	1,653	2,650		
Sep	4,868	2,915	4,836	3,263	1,879	2,727		
Oct	4,873	2,880	4,846	3,266	1,875	2,730		
Nov	4,897	2,948	4,851	3,271	1,874	2,730		
Dec	4,898	2,944	4,851	3,290	1,853	2,627		
Avg.	2,684	2,408	4,727	3,185	2,508	2,852		

Table 2-89 Distinct registrations and sites in the Economic Program: June 23, 2010[8] (See 2009 SOM, Table 2-96)

	Registrations	Sites	MW
AECO	33	39	16.4
AEP	43	43	46.6
AP	37	39	148.9
BGE	58	70	467.7
ComEd	66	67	107.9
DAY	7	7	10.1
DLCO	76	76	171.1
Dominion	28	38	97.6
DPL	26	26	65.1
JCPL	37	72	120.6
Met-Ed	33	33	41.4
PECO	116	144	151.6
PENELEC	12	12	6.7
Pepco	12	13	18.2
PPL	97	104	122.8
PSEG	45	119	298.4
RECO	1	1	0.3
Total	727	903	1,891.5

Figure 2-25 Economic Program payments: Calendar years 2007[9] through 2009 and January through June 2010[10] (See 2009 SOM, Figure 2-24)



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

9 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 2-25 do not include these incentive payments.

10 June 2010 credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve settlements, which could account for a maximum of approximately 74 calendar days.

Table 2-90 PJM Economic Program by zonal reduction: January through June 2010 (See 2009 SOM, Table 2-99)

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO							0	$25	3	0	$25	3
AEP										0	$0	0
AP	2,088	$29,627	588				44	$5,780	22	2,132	$35,406	610
BGE										0	$0	0
ComEd	34	$1,166	37				518	$12,672	324	552	$13,838	361
DAY												
DLCO												
Dominion	3,257	$208,841	153	499	$7,714	76	314	$17,812	166	4,069	$234,367	395
DPL										0	$0	0
JCPL							11	$779	28	11	$779	28
Met-Ed	2	$16	8							2	$16	8
PECO	6,434	$137,603	7,583				105	$9,187	490	6,539	$146,791	8,073
PENELEC							3	$273	14	3	$273	14
Pepco							12	$453	63	12	$453	63
PPL	390	$8,686	310				32	$2,286	85	422	$10,972	395
PSEG										0	$0	0
RECO										0	$0	0
Total	12,204	$385,939	8,679	499	$7,714	76	1,039	$49,267	1,195	13,742	$442,919	9,950
Max	6,434	$208,841	7,583	499	$7,714	76	518	$17,812	490	6,539	$234,367	8,073
Avg	2,034	$64,323	1,447	499	$7,714	76	115	$5,474	133	916	$29,528	663

Table 2-91 Settlement days submitted by month in the Economic Program: January 2007 through June 2010 (See 2009 SOM, Table 2-100)

Month	2007	2008	2009	2010
Jan	937	2,916	1,264	1,423
Feb	1,170	2,811	654	546
Mar	1,255	2,818	574	411
Apr	1,540	3,406	337	338
May	1,649	3,336	918	974
Jun	1,856	3,184	2,727	1,603
Jul	2,534	3,339	2,879	
Aug	3,962	3,848	3,760	
Sep	3,388	3,264	2,570	
Oct	3,508	1,977	2,361	
Nov	2,842	1,105	2,321	
Dec	2,675	986	1,240	
Total	26,423	32,990	21,605	5,295

Table 2-92 Distinct customers and CSPs submitting settlements in the Economic Program by month: January 2007 through June 2010 (See 2009 SOM, Table 2-101)

	2007		2008		2009		2010	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	11	72	13	261	17	257	11	162
Feb	10	89	13	243	12	129	9	92
Mar	9	87	11	216	11	149	7	124
Apr	11	98	12	208	9	76	5	77
May	12	109	12	233	9	201	19	440
Jun	12	195	17	317	20	231	22	533
Jul	15	259	16	295	21	183		
Aug	19	321	17	306	15	400		
Sep	15	279	17	312	11	181		
Oct	11	245	13	226	11	93		
Nov	10	204	14	208	9	143		
Dec	11	243	13	193	10	160		
Total Distinct Active	21	405	24	522	25	747	22	533

Table 2-93 Hourly distribution of Economic Program MWh reductions and credits: January through June 2010 (See 2009 SOM, Table 2-102)

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	51	0.37%	51	0.37%	$635	0.14%	$635	0.14%
2	58	0.42%	109	0.79%	$639	0.14%	$1,274	0.29%
3	88	0.64%	197	1.43%	$1,133	0.26%	$2,407	0.54%
4	106	0.77%	303	2.21%	$2,451	0.55%	$4,858	1.10%
5	97	0.71%	401	2.92%	$1,182	0.27%	$6,040	1.36%
6	96	0.70%	497	3.61%	$1,328	0.30%	$7,367	1.66%
7	636	4.63%	1,132	8.24%	$34,516	7.79%	$41,883	9.46%
8	1,139	8.29%	2,271	16.53%	$73,874	16.68%	$115,757	26.14%
9	1,101	8.01%	3,372	24.54%	$40,587	9.16%	$156,344	35.30%
10	784	5.70%	4,156	30.24%	$23,970	5.41%	$180,314	40.71%
11	636	4.62%	4,791	34.86%	$15,223	3.44%	$195,537	44.15%
12	623	4.53%	5,414	39.39%	$13,217	2.98%	$208,754	47.13%
13	584	4.25%	5,998	43.65%	$13,685	3.09%	$222,439	50.22%
14	593	4.31%	6,590	47.96%	$13,746	3.10%	$236,185	53.32%
15	655	4.77%	7,245	52.72%	$11,293	2.55%	$247,477	55.87%
16	574	4.18%	7,819	56.90%	$13,034	2.94%	$260,511	58.82%
17	701	5.10%	8,520	62.00%	$23,532	5.31%	$284,043	64.13%
18	884	6.43%	9,405	68.44%	$28,037	6.33%	$312,080	70.46%
19	1,111	8.08%	10,515	76.52%	$46,970	10.60%	$359,051	81.06%
20	1,031	7.50%	11,546	84.02%	$32,183	7.27%	$391,234	88.33%
21	765	5.57%	12,311	89.59%	$27,581	6.23%	$418,815	94.56%
22	614	4.47%	12,925	94.06%	$14,329	3.24%	$433,144	97.79%
23	463	3.37%	13,388	97.43%	$5,736	1.30%	$438,880	99.09%
24	354	2.57%	13,742	100.00%	$4,040	0.91%	$442,919	100.00%

Table 2-94 Distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through June 2010 (See 2009 SOM, Table 2-103)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	32	0.24%	32	0.24%	$5	0.00%	$5	0.00%
$25 to $50	7,163	52.12%	7,195	52.36%	$82,207	18.56%	$82,212	18.56%
$50 to $75	2,723	19.81%	9,918	72.17%	$70,555	15.93%	$152,766	34.49%
$75 to $100	1,197	8.71%	11,115	80.88%	$53,208	12.01%	$205,975	46.50%
$100 to $125	984	7.16%	12,099	88.04%	$59,084	13.34%	$265,059	59.84%
$125 to $150	697	5.07%	12,796	93.11%	$44,175	9.97%	$309,233	69.82%
$150 to $200	574	4.18%	13,370	97.29%	$60,047	13.56%	$369,281	83.37%
$200 to $250	203	1.48%	13,573	98.77%	$35,290	7.97%	$404,570	91.34%
$250 to $300	83	0.60%	13,656	99.38%	$16,085	3.63%	$420,655	94.97%
> $300	86	0.62%	13,742	100.00%	$22,264	5.03%	$442,919	100.00%

Emergency Program

Table 2-95 Registered sites and MW in the Emergency Program[11] (By zone and option): June 23, 2010 (See 2009 SOM, Table 2-104)

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	102	58.5	8	18.0
AEP	0	0.0	688	1,039.1	169	805.4
AP	0	0.0	672	612.0	105	180.5
BGE	0	0.0	441	758.1	28	79.3
ComEd	0	0.0	899	949.9	585	514.6
DAY	0	0.0	163	135.0	17	72.2
DLCO	0	0.0	263	158.3	13	46.4
Dominion	0	0.0	503	919.9	34	86.2
DPL	0	0.0	174	140.8	19	37.7
JCPL	0	0.0	206	161.0	19	17.5
Met-Ed	0	0.0	196	149.4	36	38.3
PECO	0	0.0	455	312.1	191	113.9
PENELEC	0	0.0	304	297.0	31	15.1
Pepco	0	0.0	265	177.8	30	38.8
PPL	0	0.0	643	671.2	87	60.1
PSEG	0	0.0	406	334.3	126	52.4
RECO	0	0.0	3	1.7	0	0.0
Total	0	0.0	6,383	6,876.0	1,498	2,176.4

Table 2-96 Registered MW in the Load Management Program by program type: Delivery years 2007/2008 through 2010/2011 (See 2009 SOM, Table 2-105)

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,020.5	6,273.8	7,294.3
2010/2011	1,070.0	7,982.4	9,052.4

11 Table 2-97 shows registered sites and MW in the Emergency Program as of June 23, 2010, the peak load day through the first six months of 2010. As all resources are registered in either the Capacity Only or Full options, all resources in the Emergency Program are considered RPM Resources participating in the Load Management (LM) Program and Table 2-98 reflects the same participation. Registered sites and MW remain constant in the LM Program through delivery years. For more information on LM Program participation and testing, see the *2009 State of the Market Report for PJM*, Volume II, Section 2 – Energy Market, Part 1: <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2-sec2.pdf>.

Table 2-97 Zonal monthly capacity credits: January 1, 2010 through June 30, 2010 (See 2009 SOM, Table 2-106)

Zone	January	February	March	April	May	June	Total
AECO	$538,827	$486,683	$387,589	$521,446	$538,827	$498,630	$2,972,002
AEP	$3,871,619	$3,496,946	$3,871,619	$3,746,728	$3,871,619	$7,469,753	$26,328,283
APS	$3,380,342	$3,053,212	$3,082,016	$3,271,298	$3,380,342	$4,134,986	$20,302,196
BGE	$4,971,814	$4,490,671	$4,613,517	$4,811,433	$4,971,814	$4,877,253	$28,736,503
ComEd	$4,423,355	$3,995,288	$4,357,876	$4,280,666	$4,423,355	$7,893,843	$29,374,382
DAY	$667,966	$603,324	$667,966	$646,419	$667,966	$1,114,399	$4,368,041
DLCO	$387,642	$350,129	$387,642	$375,138	$387,642	$1,082,462	$2,970,655
Dominion	$1,655,820	$1,495,580	$1,655,820	$1,602,407	$1,655,820	$5,271,768	$13,337,216
DPL	$1,117,919	$1,009,733	$1,004,045	$1,081,857	$1,117,919	$1,053,129	$6,384,600
JCPL	$1,374,149	$1,241,167	$897,896	$1,329,822	$1,374,149	$1,259,066	$7,476,248
Met-Ed	$1,357,392	$1,226,031	$1,357,392	$1,313,605	$1,357,392	$1,166,215	$7,778,027
PECO	$2,717,550	$2,454,561	$2,120,899	$2,629,887	$2,717,550	$2,735,060	$15,375,506
PENELEC	$1,325,705	$1,197,411	$1,325,705	$1,282,941	$1,325,705	$1,768,655	$8,226,123
Pepco	$1,161,239	$1,048,861	$814,714	$1,123,780	$1,161,239	$1,265,186	$6,575,019
PPL	$3,583,739	$3,236,926	$3,617,545	$3,468,134	$3,583,739	$3,982,417	$21,472,500
PSEG	$2,266,920	$2,047,540	$1,777,619	$2,193,793	$2,266,920	$2,454,980	$13,007,772
RECO	$24,425	$22,061	$18,494	$23,637	$24,425	$8,967	$122,008
Total	$34,826,423	$31,456,124	$31,958,354	$33,702,990	$34,826,423	$48,036,768	$214,807,081

Table 2-98 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007/2008 through 2013/2014 (See 2009 SOM, Table 2-107)

Planning Year	DR Offered in BRA	DR Cleared in BRA
2007/2008	123.5	123.5
2008/2009	691.9	518.5
2009/2010	906.9	865.2
2010/2011	935.6	908.1
2011/2012	1,597.3	1,319.5
2012/2013	9,535.4	6,824.1
2013/2014	12,528.7	8,977.4