SECTION 2 – ENERGY MARKET, PART 1

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for January through September of 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 nine 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 third quarter of 2010, the PJM Energy Market received an hourly average of 155,322 MWh in supply offers including hydroelectric generation.[3] The third quarter 2010 average daily offered supply was 1,624 MWh higher than the third quarter 2009 average daily offered supply of 153,698 MWh.

- **Demand.** The PJM system peak load for the third quarter 2010 was 136,460 MW in the hour ended 1600 EPT on July 6, 2010, while the PJM peak load for the third quarter 2009 was 126,798 MW in the hour ended 1600 EPT on August 10, 2009.[4] The third quarter 2010 peak load was 9,662 MW, or 7.6 percent, higher than the third 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 September*, 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 nine months of 2010. In the Real-Time Energy Market offer-capped unit hours increased from 0.4 percent in 2009 to 1.2 percent in the period from January through September 2010.

On June 9, 2010, PJM replaced the Look-Ahead Unit Dispatch Software (LA UDS) with new short run look ahead Security Constrained Economic Dispatch (SCED 2; or IT SCED) optimization software. The three pivotal supplier test (TPS) is now run in SCED 2. 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.

- **Local Market Structure.** For the period July 1, 2010 through September 30, 2010, a summary of the TPS results based on SCED is presented for all constraints which occurred for 25 or more hours.

  During July, August and September of 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The analysis of the application of the 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 nine months of 2010 was $0.49 per MWh, or 1.0 percent. Coal steam units contributed -$1.14 to the total markup component of LMP. Combustion turbine units that use natural gas as their primary fuel source contributed $0.41 to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.97 to the total markup component of LMP. The markup was $2.04 per MWh during peak hours and -$1.18 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP for the first nine months of 2010 was -$0.60 per MWh, or -1.2 percent. Coal steam units contributed -$0.72 to the total markup component of LMP. Natural gas steam units contributed $0.09 to the total markup component of LMP. The markup was $0.04 per MWh during peak hours and -$1.29 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 nine months of 2010 by 5.3 percent from the first nine months of 2009, rising from 76,956 MW to 81,068 MW. PJM day-ahead load increased in the first nine months of 2010 by 3.3 percent from the first nine months of 2009, rising from 89,680 MW to 92,683 MW.

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

PJM Real-Time Energy Market prices increased in the first nine months of 2010 compared to the first nine months of 2009. The system simple average LMP was 23.3 percent higher in the first nine months of 2010 than in the first nine months of 2009, $46.13 per MWh versus $37.42 per MWh. The load-weighted LMP was 26.2 percent higher in the first nine months of 2010 than the first nine months of 2009, $49.91 per MWh versus $39.57 per MWh. The real-time, fuel cost adjusted, load-weighted, average LMP[5] was 25.7 percent higher for the first nine months of 2010 than the load-weighted, average LMP for the first nine months of 2009, $49.74 per MWh versus $39.57 per MWh. In other words, if fuel costs in the first nine months of 2010 were the same as they had been in the first nine months of 2009, the 2010 load-weighted LMP would have been 0.3 percent lower, $49.74 per MWh, than the actual $49.91 per MWh, and 25.7 percent higher than the load-weighted average LMP for the first nine months of 2009. Higher loads and fuel costs contributed to upward pressure on LMP in the first nine months of 2010.

PJM Day-Ahead Energy Market prices increased in the first nine months of 2010 compared to the first nine months of 2009. The system simple average LMP was 22.7 percent higher in the first nine months of 2010 than in the first nine months of 2009, $45.81 per MWh versus $37.35 per MWh. The load-weighted LMP was 24.8 percent higher in the first nine months of 2010 than in the first nine months of 2009, $49.12 per MWh versus $39.35 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 nine months of 2010, 11.5 percent of real-time load was supplied by bilateral contracts, 19.4 percent by spot market purchases and 69.1 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 1.3 percentage points; reliance on spot supply increased by 2.4 percentage points; and reliance on self-supply decreased by 1.0 percentage points in 2010.

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

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 nine months of 2010, in the Economic Program, participation was more concentrated compared to the first nine months of 2009. Settled MWh were approximately the same compared to the same period in 2009, while credits were significantly higher in 2010 due to higher price levels. However, there were generally fewer settlements submitted, fewer registered customers, and fewer active customers compared to the same period in 2009. Participation levels through calendar year 2009 and through the first three months of 2010 were generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification, but have showed strong growth through the second and third quarter as price levels and load levels have increased. On the peak load day for the period January through September 2010 (July 6, 2010), there were 1,725.7 MW registered in the Economic Load Response Program.

In the first nine months of 2010, the Emergency Program, specifically, the Load Management (LM) Program, participation increased compared to the same period in 2009.[6] 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 8,875.9 MW registered in the LM Program, compared to 7,294.3 MW registered in the 2009/2010 delivery year.

There were six PJM Load Management Events declared in 2010, five were within the summer compliance period (June 1 through September 30) and one was declared before the summer period on May 26. Both the May 26 and the June 11 events were called for the District of Columbia (DC) portions of Pepco. The June 11 event marks the first time that PJM called a load management event at a sub-zonal level within the compliance period. Prior to this point, load management events and thus compliance were aggregated to a zonal basis. While all PJM Emergency Actions, including Load Management Events, may be issued for part of a zone, the only locational requirement for the aggregation of multiple end use customers to a single registration is that they reside in the same control zone. Similarly, compliance for testing and for zonal Emergency Events, is aggregated for each Curtailment Service Provider (CSP) to a zonal basis. Some market participants were not prepared to deploy resources at a sub-zonal level, and they submitted compliance data for all resources located in Pepco. Preliminary results for the June 11 event show that resources within the DC portion of Pepco zone accounted for load reductions in excess of 90 percent of total nominated ICAP.

If reductions for outside the DC portion of Pepco were to be included for event compliance, yet compliance was determined only considering commitments within the DC portion of Pepco, then the level of compliance derived, in excess of 200 percent, would be overstated and meaningless, as it would measure compliance by comparing load reductions from participants outside the affected area, which do not affect the level of required load reductions in the subzone, to the level of commitments inside the subzone.[7] However, if compliance is calculated for all resources within Pepco for which data were submitted, taking into account both reductions and nominal commitments from outside the DC portion of Pepco, compliance is significantly less than nominated commitments, below 70 percent. While it may be reasonable to consider a broader geographical area as one element of evaluating compliance, it is not logical to compare reductions from outside the DC portion of Pepco to commitments inside the DC portion of Pepco. Regardless of the geographical scope, any compliance calculation should reflect the nominated commitment of any resource for which a reduction is considered. That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are assessed compliance on a zonal basis, represents a broader issue that needs to be addressed. More precise locational deployment of Load Management leads to system efficiencies, however, it reduces the ability of a CSP to aggregate customers and spread risk over a geographical area within a zone.

Preliminary results for the July 7 event for EMAAC, SWMAAC and Dominion zones show load reductions greater than 90 percent of total nominated ICAP.[8] The proportion of customers meeting nominated commitments is substantially lower for both events, less than 50 percent, which implies significant over compliance from a subset of larger customers. Further, the MMU has raised concerns with PJM and stakeholders on the measurement and verification protocols in place to quantify load reductions for the 2010/2011 delivery year and these methods will be under review in calendar year 2011.

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 nine months of 2010. In the first nine months of 2010, payments from the Economic Program increased from the first nine months of 2009 by $948,000 or 82 percent, from $1.2 Million to $2.1 Million while capacity revenue increased from the first nine months of 2009 by $154 million or 74 percent, from $208 million to $362 million since 2009.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the first nine months of 2010, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation

6 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.

7 This appears to be the level of compliance shown for the June 11 event in the preliminary compliance report released by PJM. See: http://www.pjm.com/~/media/markets-ops/dsr/emergency-load-management-events-2010-preliminary-summary.ashx

8 Compliance figures are preliminary and are based on registered nominal reductions which do not consider replacement capacity transactions. Complete data for the September events are not yet available.

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 hourly supply offered increased by about 1,624 MWh when comparing the third quarter of 2010 to the third quarter of 2009, while aggregate peak load increased by 9,662 MW, modifying the general supply demand balance from the third quarter of 2009 with a corresponding impact on Energy Market prices. Average load in the first nine months of 2010 also increased from the first nine months of 2009, rising from 76,956 MW to 81,068 MW. Market concentration levels remained moderate and average markup was slightly positive. This relationship between supply and demand, regardless of the specific market, balanced by market concentration and residual supplier levels, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

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

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.[9] The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests.

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

Energy Market results for the first nine months of 2010 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher demand and higher fuel costs. PJM Real-Time, load-weighted, average LMP for the first nine months of 2010 was $49.91, or 26.2 percent higher than the load-weighted, average LMP for the first nine months of 2009, which was $39.57. The real-time fuel cost adjusted, load-weighted, average LMP was 25.7 percent higher for the first nine months of 2010 than the load-weighted, average LMP in for the first nine months of 2009, $49.74 per MWh compared to $39.57 per MWh. In other words, if fuel costs in the first nine months of 2010 were the same as they had been in the first nine months of 2009, the 2010 load-weighted LMP would have been 0.3 percent lower, $49.74 per MWh, than the actual $49.91 per MWh, and 25.7 percent higher than the load-weighted average LMP for the first nine months of 2009. Higher loads and fuel costs contributed to upward pressure on LMP in the first nine months of 2010.

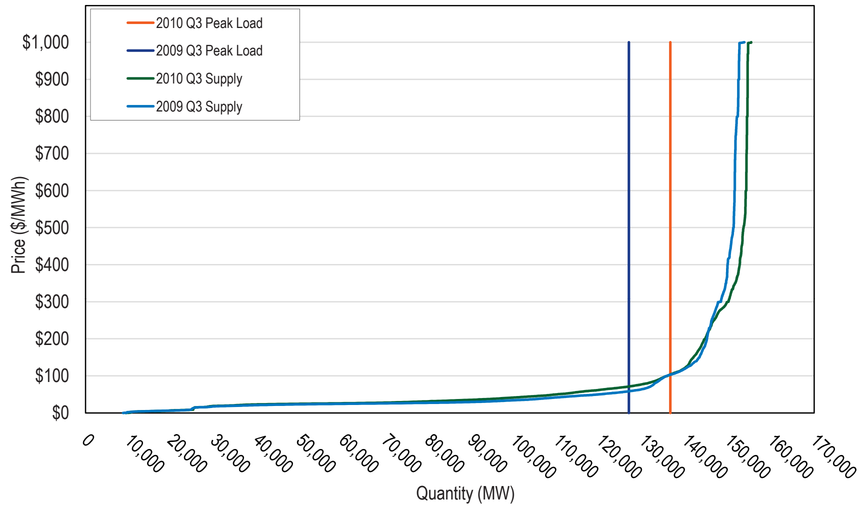
The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change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

9 See *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶61,321 (1997); FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶61,157 (2008).

Market Structure

Supply

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



Demand

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

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)	Difference (%)
2003	Fri, August 22	15	61,499	NA	NA
2004	Tue, August 03	16	77,887	16,387	26.6%
2005	Tue, July 26	15	133,761	55,875	71.7%
2006	Wed, August 02	16	144,644	10,883	8.1%
2007	Wed, August 08	15	139,428	(5,216)	(3.6%)
2008	Thu, July 17	16	129,481	(9,947)	(7.1%)
2009	Mon, August 10	16	126,798	(2,683)	(2.1%)
2010	Tue, July 06	16	136,460	9,662	7.6%

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

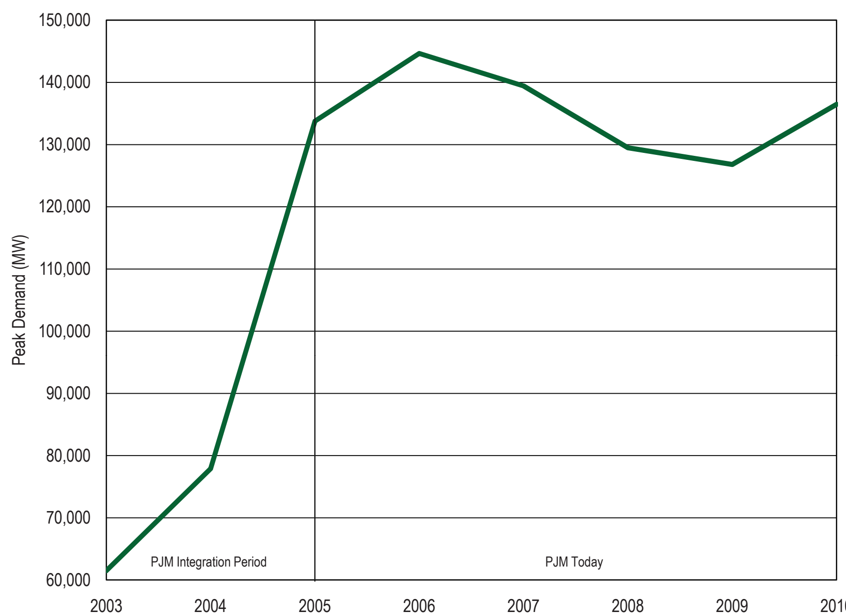
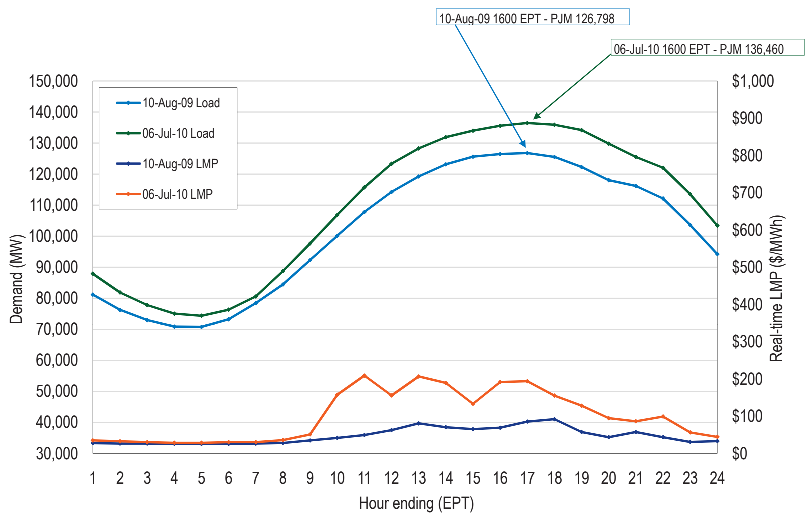


Figure 2-3 PJM third quarter peak-load comparison: Tuesday, July 06, 2010 and Monday, August 10, 2009 (See 2009 SOM, Figure 2-3)



Market Concentration

PJM HHI Results[10]

Table 2-2 PJM hourly Energy Market HHI: January through September 2010[11] (See 2009 SOM, Table 2-2)

	Hourly Market HHI
Average	1180
Minimum	914
Maximum	1599
Highest market share (One hour)	31%
Highest market share (All hours)	20%
# Hours	6,551
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

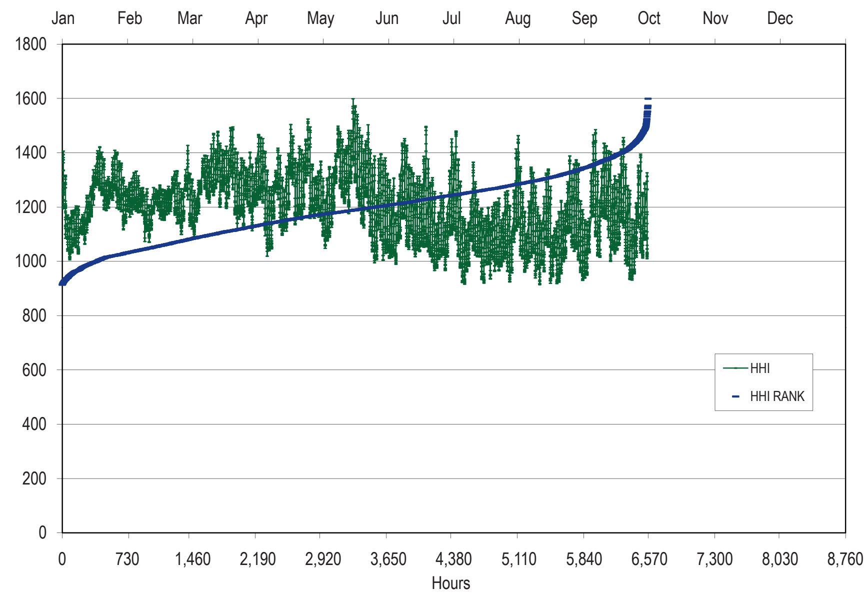
10 HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. This assumption and related conclusion are not generally correct in electricity markets where location and unit specific parameters are significant determinants of the costs to provide service, not the relative market share of the participant. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

11 This analysis includes all hours of the first nine months of 2010, regardless of congestion.

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

	Minimum	Average	Maximum
Base	1070	1241	1550
Intermediate	681	1747	7279
Peak	606	6160	10000

Figure 2-4 PJM hourly Energy Market HHI: January through September 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 September 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	1.2%	0.3%	0.3%	0.1%

Table 2-5 Real-time offer-capped unit statistics: January through September 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%	2	1	0	0	2	15
80% and < 90%	1	0	1	6	8	17
75% and < 80%	0	0	0	0	0	6
70% and < 75%	1	0	0	0	4	11
60% and < 70%	0	0	3	0	3	36
50% and < 60%	0	0	0	3	1	17
25% and < 50%	2	0	1	1	19	48
10% and < 25%	1	1	0	1	8	36

Local Market Structure[12]

Table 2-6 Three pivotal supplier results summary for regional constraints: July 1, 2010 through September 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	4,280	513	12%	4,077	95%
	Off Peak	1,299	203	16%	1,205	93%
AP South	Peak	4,711	135	3%	4,660	99%
	Off Peak	1,920	50	3%	1,899	99%
Bedington - Black Oak	Peak	8	1	13%	7	88%
	Off Peak	62	29	47%	50	81%
Central	Peak	40	8	20%	36	90%
	Off Peak	45	13	29%	35	78%
Doubs - Mount Storm	Peak	848	17	2%	837	99%
	Off Peak	674	5	1%	672	100%
East	Peak	4	2	50%	3	75%
	Off Peak	NA	NA	NA	NA	NA
Harrison - Pruntytown	Peak	3,188	302	9%	3,041	95%
	Off Peak	2,960	133	4%	2,889	98%
West	Peak	189	47	25%	167	88%
	Off Peak	NA	NA	NA	NA	NA

12 Effective June 9, 2010, 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, through September 30, 2010, the MMU is reporting SCED 2 based TPS results for regional 500 kV constraints.

Table 2-7 Three pivotal supplier results details for regional constraints: July 1, 2010 through September 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	368	2,178	18	2	16
	Off Peak	304	1,719	15	2	13
AP South	Peak	297	900	8	0	8
	Off Peak	382	793	7	0	7
Bedington - Black Oak	Peak	189	299	8	1	8
	Off Peak	148	1,211	9	3	6
Central	Peak	633	4,058	20	4	16
	Off Peak	574	3,228	15	5	10
Doubs - Mount Storm	Peak	195	1,170	15	0	15
	Off Peak	321	1,430	16	0	16
East	Peak	389	2,969	17	9	8
	Off Peak	NA	NA	NA	NA	NA
Harrison - Pruntytown	Peak	431	1,941	16	1	15
	Off Peak	484	2,020	15	1	15
West	Peak	707	4,455	19	4	14
	Off Peak	NA	NA	NA	NA	NA

Table 2-8 Three pivotal supplier test summary for constraints located in the AECO Control Zone: July 1, 2010 through September 30, 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
Monroe	Peak	1,134	0	0%	1,134	100%
	Off Peak	46	0	0%	46	100%
Shieldalloy - Vineland	Peak	1,737	0	0%	1,737	100%
	Off Peak	1,914	0	0%	1,914	100%

Table 2-9 Three pivotal supplier test details for constraints located in the AECO Control Zone: July 1, 2010 through September 30, 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
Monroe	Peak	7	6	2	0	2
	Off Peak	8	7	2	0	2
Shieldalloy - Vineland	Peak	12	13	2	0	2
	Off Peak	10	11	1	0	1

Table 2-10 Three pivotal supplier results summary for constraints located in the AEP Control Zone: July 1, 2010 through September 30, 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
Brues - West Bellaire	Peak	303	0	0%	303	100%
	Off Peak	767	0	0%	767	100%
Carnegie - Tidd	Peak	2,146	0	0%	2,146	100%
	Off Peak	342	0	0%	342	100%
Cloverdale	Peak	776	72	9%	759	98%
	Off Peak	2,717	57	2%	2,707	100%
Cloverdale - Ivy Hill	Peak	434	0	0%	434	100%
	Off Peak	310	0	0%	310	100%
Cloverdale - Lexington	Peak	1,682	308	18%	1,555	92%
	Off Peak	8,064	591	7%	7,971	99%
Dumont - Stillwell	Peak	147	16	11%	136	93%
	Off Peak	1,526	73	5%	1,470	96%
Kammer - Natrium	Peak	336	0	0%	336	100%
	Off Peak	371	0	0%	371	100%
Mahans Lane - Tidd	Peak	1,277	0	0%	1,277	100%
	Off Peak	922	0	0%	922	100%
Poston - Postel Tap	Peak	1,715	0	0%	1,715	100%
	Off Peak	286	0	0%	286	100%
Ruth - Turner	Peak	52	0	0%	52	100%
	Off Peak	683	0	0%	683	100%

Table 2-11 Three pivotal supplier test details for constraints located in the AEP Control Zone: July 1, 2010 through September 30, 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
Brues - West Bellaire	Peak	9	12	1	0	1
	Off Peak	18	21	1	0	1
Carnegie - Tidd	Peak	29	28	1	0	1
	Off Peak	46	20	1	0	1
Cloverdale	Peak	183	1,163	11	1	10
	Off Peak	193	1,266	8	0	8
Cloverdale - Ivy Hill	Peak	3	3	1	0	1
	Off Peak	4	3	1	0	1
Cloverdale - Lexington	Peak	184	1,830	16	2	14
	Off Peak	192	1,811	12	1	11
Dumont - Stillwell	Peak	252	1,961	21	2	19
	Off Peak	214	1,490	15	1	14
Kammer - Natrium	Peak	11	9	1	0	1
	Off Peak	13	17	1	0	1
Mahans Lane - Tidd	Peak	14	20	1	0	1
	Off Peak	13	20	1	0	1
Poston - Postel Tap	Peak	13	39	1	0	1
	Off Peak	4	20	1	0	1
Ruth - Turner	Peak	3	4	1	0	1
	Off Peak	12	6	1	0	1

Table 2-12 Three pivotal supplier results summary for constraints located in the AP Control Zone: July 1, 2010 through September 30, 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
Armstrong - Burma	Peak	268	0	0%	268	100%
	Off Peak	104	0	0%	104	100%
Bedington - Harmony	Peak	1,160	0	0%	1,160	100%
	Off Peak	388	0	0%	388	100%
Bedington - Shepherdstown	Peak	622	0	0%	622	100%
	Off Peak	60	0	0%	60	100%
Belmont	Peak	1,379	0	0%	1,379	100%
	Off Peak	494	0	0%	494	100%
Butler - Karns City	Peak	166	0	0%	166	100%
	Off Peak	843	0	0%	843	100%
Doubs	Peak	3,402	1	0%	3,402	100%
	Off Peak	401	0	0%	401	100%
Elrama - Mitchell	Peak	1,806	5	0%	1,805	100%
	Off Peak	6,658	5	0%	6,657	100%
Kingwood - Pruntytown	Peak	277	0	0%	277	100%
	Off Peak	251	0	0%	251	100%
Millvile - Sleepy Hollow	Peak	6,118	0	0%	6,118	100%
	Off Peak	1,754	0	0%	1,754	100%
Millville - Old Chapel	Peak	2,575	0	0%	2,575	100%
	Off Peak	1,276	0	0%	1,276	100%
Mount Storm - Pruntytown	Peak	5,901	659	11%	5,695	97%
	Off Peak	9,016	441	5%	8,909	99%
Muskingum River - East Newcon	Peak	426	0	0%	426	100%
	Off Peak	NA	NA	NA	NA	NA
Tiltonsville - Windsor	Peak	1,363	0	0%	1,363	100%
	Off Peak	528	0	0%	528	100%
Wylie Ridge	Peak	4,218	519	12%	3,947	94%
	Off Peak	8,826	723	8%	8,544	97%

Table 2-13 Three pivotal supplier test details for constraints located in the AP Control Zone: July 1, 2010 through September 30, 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
Armstrong - Burma	Peak	15	31	1	0	1
	Off Peak	9	13	2	0	2
Bedington - Harmony	Peak	17	9	2	0	2
	Off Peak	18	10	2	0	2
Bedington - Shepherdstown	Peak	26	4	1	0	1
	Off Peak	15	5	1	0	1
Belmont	Peak	18	24	1	0	1
	Off Peak	11	13	2	0	2
Butler - Karns City	Peak	6	10	2	0	2
	Off Peak	14	14	1	0	1
Doubs	Peak	14	17	3	0	3
	Off Peak	12	5	2	0	2
Elrama - Mitchell	Peak	64	76	3	0	3
	Off Peak	97	99	3	0	3
Kingwood - Pruntytown	Peak	6	3	1	0	1
	Off Peak	10	4	1	0	1
Millvile - Sleepy Hollow	Peak	41	21	2	0	2
	Off Peak	24	9	1	0	1
Millville - Old Chapel	Peak	43	17	2	0	2
	Off Peak	53	7	1	0	1
Mount Storm - Pruntytown	Peak	329	1,446	10	1	9
	Off Peak	343	1,427	9	0	8
Muskingum River - East Newcon	Peak	6	8	1	0	1
	Off Peak	NA	NA	NA	NA	NA
Tiltonsville - Windsor	Peak	16	11	1	0	1
	Off Peak	20	15	1	0	1
Wylie Ridge	Peak	184	1,036	18	2	16
	Off Peak	189	922	13	1	13

Table 2-14 Three pivotal supplier results summary for constraints located in the BGE Control Zone: July 1, 2010 through September 30, 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	2,038	213	10%	1,928	95%
	Off Peak	411	67	16%	380	92%
Graceton - Safe Harbor	Peak	NA	NA	NA	NA	NA
	Off Peak	566	381	67%	258	46%

Table 2-15 Three pivotal supplier test details for constraints located in the BGE Control Zone: July 1, 2010 through September 30, 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	64	370	12	1	10
	Off Peak	53	362	10	1	9
Graceton - Safe Harbor	Peak	NA	NA	NA	NA	NA
	Off Peak	53	737	12	9	2

Table 2-16 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: July 1, 2010 through September 30, 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 - Sheffield	Peak	907	0	0%	907	100%
	Off Peak	665	0	0%	665	100%
Cherry Valley	Peak	782	0	0%	782	100%
	Off Peak	35	0	0%	35	100%
East Frankfort - Crete	Peak	1,346	7	1%	1,342	100%
	Off Peak	4,190	33	1%	4,166	99%
Electric Jct - Nelson	Peak	1,281	3	0%	1,280	100%
	Off Peak	985	0	0%	985	100%
Nelson - Cordova	Peak	1,098	18	2%	1,089	99%
	Off Peak	290	0	0%	290	100%
Pleasant Valley - Belvidere	Peak	616	0	0%	616	100%
	Off Peak	1131	0	0%	1131	100%
Waterman - West Dekalb	Peak	220	0	0%	220	100%
	Off Peak	622	0	0%	622	100%
Wayne - 7910	Peak	377	0	0%	377	100%
	Off Peak	177	0	0%	177	100%
Wayne - 7915	Peak	1,285	0	0%	1,285	100%
	Off Peak	123	0	0%	123	100%

Table 2-17 Three pivotal supplier test details for constraints located in the ComEd Control Zone: July 1, 2010 through September 30, 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 - Sheffield	Peak	117	1,403	2	0	2
	Off Peak	187	1,383	3	0	3
Cherry Valley	Peak	5	7	1	0	1
	Off Peak	1	2	1	0	1
East Frankfort - Crete	Peak	114	931	3	0	3
	Off Peak	115	1,101	3	0	3
Electric Jct - Nelson	Peak	42	28	3	0	3
	Off Peak	15	9	2	0	2
Nelson - Cordova	Peak	51	294	5	0	5
	Off Peak	39	152	2	0	2
Pleasant Valley - Belvidere	Peak	13	5	2	0	2
	Off Peak	3	2	1	0	1
Waterman - West Dekalb	Peak	6	17	1	0	1
	Off Peak	6	25	1	0	1
Wayne - 7910	Peak	19	24	1	0	1
	Off Peak	1	7	1	0	1
Wayne - 7915	Peak	29	33	1	0	1
	Off Peak	18	19	1	0	1

Table 2-18 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: July 1, 2010 through September 30, 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
Arsenal - Oakland	Peak	1,407	0	0%	1,407	100%
	Off Peak	156	0	0%	156	100%

Table 2-19 Three pivotal supplier test details for constraints located in the DLCO Control Zone: July 1, 2010 through September 30, 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
Arsenal - Oakland	Peak	39	45	2	0	2
	Off Peak	20	28	2	0	2

Table 2-20 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: July 1, 2010 through September 30, 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	4,452	0	0%	4,452	100%
	Off Peak	740	0	0%	740	100%
Benning - Ritchie	Peak	995	0	0%	995	100%
	Off Peak	1	0	0%	1	100%
Chaparral - Locks	Peak	678	3	0%	678	100%
	Off Peak	443	2	0%	443	100%
Clover	Peak	5,664	9	0%	5,659	100%
	Off Peak	972	2	0%	972	100%
Danville - East Danville	Peak	504	0	0%	504	100%
	Off Peak	1,309	0	0%	1,309	100%
Dooms	Peak	857	0	0%	857	100%
	Off Peak	95	0	0%	95	100%
Five Forks - Rock Ridge	Peak	711	0	0%	711	100%
	Off Peak	646	0	0%	646	100%
Halifax - Mount Laurel	Peak	1,301	0	0%	1,301	100%
	Off Peak	179	0	0%	179	100%

Table 2-21 Three pivotal supplier test details for constraints located in the Dominion Control Zone: July 1, 2010 through September 30, 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	9	37	1	0	1
	Off Peak	9	31	1	0	1
Benning - Ritchie	Peak	18	50	1	0	1
	Off Peak	10	61	1	0	1
Chaparral - Locks	Peak	93	327	4	0	4
	Off Peak	78	371	4	0	4
Clover	Peak	86	256	3	0	3
	Off Peak	101	242	3	0	3
Danville - East Danville	Peak	40	31	2	0	2
	Off Peak	58	45	2	0	2
Dooms	Peak	79	194	2	0	2
	Off Peak	86	160	2	0	2
Five Forks - Rock Ridge	Peak	17	13	1	0	1
	Off Peak	16	11	1	0	1
Halifax - Mount Laurel	Peak	8	10	1	0	1
	Off Peak	6	7	1	0	1

Table 2-22 Three pivotal supplier results summary for constraints located in the DPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Edgemoor At20	Peak	266	0	0%	266	100%
	Off Peak	784	0	0%	784	100%
Greenbush - Hallwood	Peak	491	0	0%	491	100%
	Off Peak	606	0	0%	606	100%
Kenney - Stockton	Peak	2,492	0	0%	2,492	100%
	Off Peak	418	0	0%	418	100%

Table 2-23 Three pivotal supplier test details for constraints located in the DPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Edgemoor At20	Peak	222	282	2	0	2
	Off Peak	31	38	2	0	2
Greenbush - Hallwood	Peak	4	5	1	0	1
	Off Peak	9	9	1	0	1
Kenney - Stockton	Peak	32	35	1	0	1
	Off Peak	12	12	1	0	1

Table 2-24 Three pivotal supplier results summary for constraints located in the JCPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Redoak - Sayreville	Peak	1,572	14	1%	1,570	100%
	Off Peak	51	0	0%	51	100%

Table 2-25 Three pivotal supplier test details for constraints located in the JCPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Redoak - Sayreville	Peak	48	100	4	0	4
	Off Peak	16	25	2	0	2

Table 2-26 Three pivotal supplier results summary for constraints located in the Met-Ed Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Brunner Island - Yorkana	Peak	4,607	693	15%	4,315	94%
	Off Peak	1,371	19	1%	1,357	99%
Jackson - TMI	Peak	1,660	238	14%	1,525	92%
	Off Peak	195	24	12%	180	92%

Table 2-27 Three pivotal supplier test details for constraints located in the Met-Ed Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brunner Island - Yorkana	Peak	69	470	11	1	9
	Off Peak	69	416	6	0	6
Jackson - TMI	Peak	54	313	10	2	8
	Off Peak	61	452	9	1	8

Table 2-28 Three pivotal supplier results summary for constraints located in the PECO Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-24)

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
Eddystone - Saville	Peak	855	76	9%	849	99%
	Off Peak	NA	NA	NA	NA	NA

Table 2-29 Three pivotal supplier test details for constraints located in the PECO Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-25)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Eddystone - Saville	Peak	9	34	3	0	3
	Off Peak	NA	NA	NA	NA	NA

Table 2-30 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-26)

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
Altoona - Bear Rock	Peak	910	0	0%	910	100%
	Off Peak	327	0	0%	327	100%
Bear Rock - Johnstown	Peak	1,953	0	0%	1,953	100%
	Off Peak	52	0	0%	52	100%
East Sayre - East Towanda	Peak	274	0	0%	274	100%
	Off Peak	369	0	0%	369	100%
Roxbury - Shade Gap	Peak	1,102	0	0%	1,102	100%
	Off Peak	619	0	0%	619	100%

Table 2-31 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-27)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Altoona - Bear Rock	Peak	17	31	2	0	2
	Off Peak	22	15	1	0	1
Bear Rock - Johnstown	Peak	24	43	2	0	2
	Off Peak	12	31	2	0	2
East Sayre - East Towanda	Peak	15	18	2	0	2
	Off Peak	7	16	2	0	2
Roxbury - Shade Gap	Peak	14	14	3	0	3
	Off Peak	22	21	3	0	3

Table 2-32 Three pivotal supplier results summary for constraints located in the Pepco Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-28)

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
Burtonsville - Sandy Springs	Peak	907	11	1%	901	99%
	Off Peak	NA	NA	NA	NA	NA

Table 2-33 Three pivotal supplier test details for constraints located in the Pepco Control Zone: July 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-29)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burtonsville - Sandy Springs	Peak	60	275	7	0	6
	Off Peak	NA	NA	NA	NA	NA

Table 2-34 Three pivotal supplier results summary for constraints located in the PPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Eldred - Sunbury	Peak	1,526	0	0%	1,526	100%
	Off Peak	30	0	0%	30	100%
Harwood - Siegfried	Peak	2,892	53	2%	2,873	99%
	Off Peak	2,054	6	0%	2,053	100%

Table 2-35 Three pivotal supplier test details for constraints located in the PPL Control Zone: July 1, 2010 through September 30, 2010 (New Table)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Eldred - Sunbury	Peak	30	92	4	0	4
	Off Peak	18	69	3	0	3
Harwood - Siegfried	Peak	86	532	6	0	6
	Off Peak	96	570	6	0	6

Table 2-36 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: July 1, 2010 through September 30, 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
Bergen - Hoboken	Peak	337	0	0%	337	100%
	Off Peak	300	0	0%	300	100%
Branchburg - Readington	Peak	508	4	1%	507	100%
	Off Peak	17	0	0%	17	100%
Linden - North Ave	Peak	802	0	0%	802	100%
	Off Peak	4	0	0%	4	100%

Table 2-37 Three pivotal supplier test details for constraints located in the PSEG Control Zone: July 1, 2010 through September 30, 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
Bergen - Hoboken	Peak	59	76	1	0	1
	Off Peak	17	30	1	0	1
Branchburg - Readington	Peak	38	85	4	0	4
	Off Peak	13	37	2	0	2
Linden - North Ave	Peak	94	114	1	0	1
	Off Peak	52	85	1	0	1

Market Performance: Markup

Real-Time Markup

Ownership of Marginal Resources

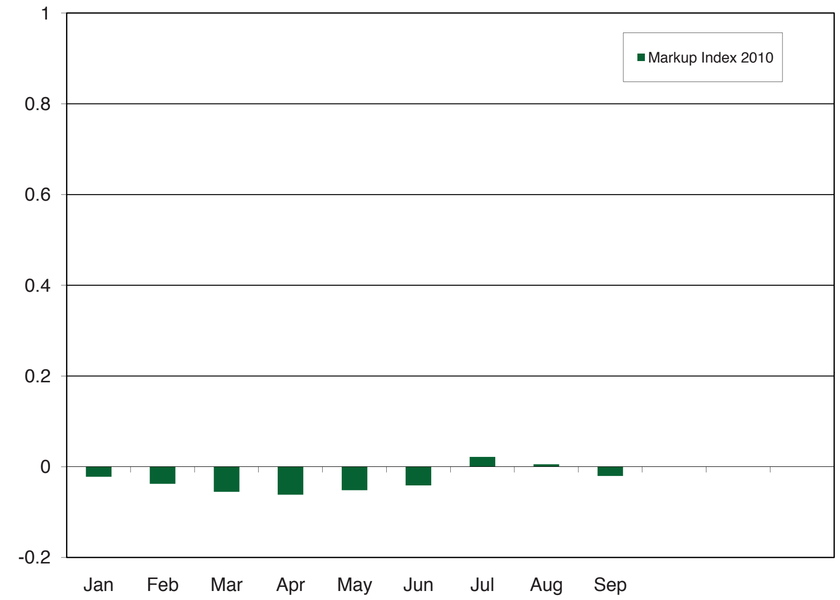
Table 2-38 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through September 2010 (See 2009 SOM, Table 2-32)

Company	Percent of Price
1	16%
2	12%
3	10%
4	6%
5	5%
6	5%
7	4%
8	4%
9	4%
Other (54 companies)	34%

Table 2-39 Type of fuel used (By real-time marginal units): January through September 2010 (See 2009 SOM, Table 2-33)

Fuel Type	2010
Coal	66%
Natural Gas	26%
Petroleum	4%
Wind	2%
Landfill Gas	1%
Misc	1%

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



Unit Markup Characteristics

Table 2-40 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September 2010 (See 2009 SOM, Table 2-34)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.14)	(234.6%)
Gas	CC	$0.97	199.5%
Gas	CT	$0.41	85.0%
Gas	Diesel	($0.00)	(0.1%)
Gas	Steam	$0.04	8.4%
Interface	Interface	($0.00)	(0.0%)
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.01	2.1%
Oil	CT	$0.02	5.1%
Oil	Diesel	($0.00)	(0.8%)
Oil	Steam	$0.14	28.7%
Uranium	Steam	$0.00	0.0%
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.03	6.7%
Total		$0.49	100.0%

Table 2-41 Average, real-time marginal unit markup index (By price category): January through September 2010 (See 2009 SOM, Table 2-35)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.10)	($3.27)
$25 to $50	(0.07)	($2.89)
$50 to $75	0.04	$1.88
$75 to $100	0.09	$7.39
$100 to $125	0.10	$10.75
$125 to $150	0.12	$16.48
> $150	0.08	$17.32

Markup Component of System Price

Table 2-42 Monthly markup components of real-time load-weighted LMP: January through September 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	($1.46)	($2.09)	($0.71)
Jul	$7.22	$12.54	$1.65
Aug	$3.53	$6.77	($0.28)
Sep	$0.66	$2.15	($1.08)
2010	$0.49	$2.04	($1.18)

Markup by Real-Time System Price Levels

Table 2-43 Average real-time markup component (By price category): January through September 2010 (See 2009 SOM, Table 2-38)

	Average Markup Component	Frequency
Below $20	($1.82)	2.4%
$20 to $40	($3.35)	53.4%
$40 to $60	($0.87)	26.6%
$60 to $80	$6.12	8.8%
$80 to $100	$1.97	3.9%
$100 to $120	$16.83	2.1%
$120 to $140	$19.36	1.2%
$140 to $160	$22.63	0.6%
Above $160	$52.94	0.9%

Day-Ahead Markup

Ownership of Marginal Resources

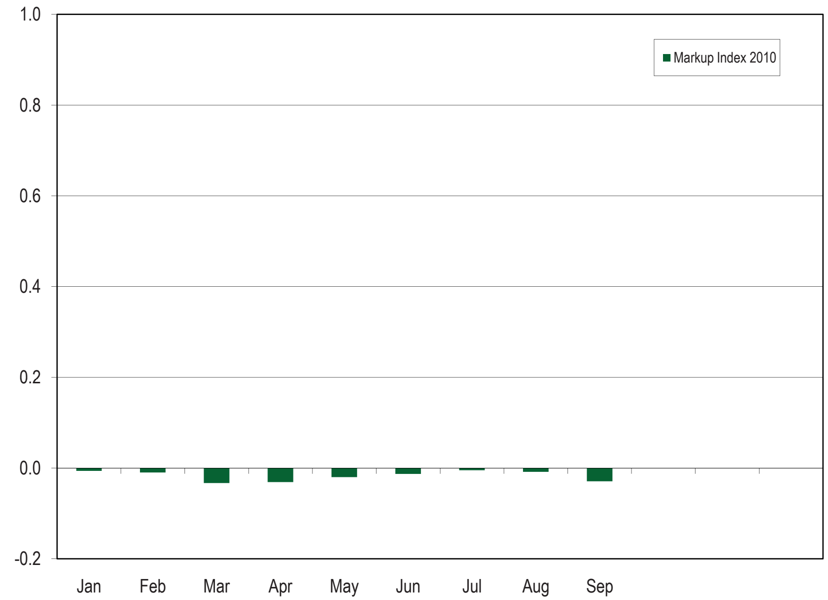
Table 2-44 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through September 2010 (See 2009 SOM, Table 2-39)

Company	Percent of Price
1	24%
2	6%
3	5%
4	5%
5	5%
6	5%
7	5%
8	4%
9	3%
Other (131 companies)	38%

Table 2-45 Day-ahead marginal resources by type/fuel: January through September 2010 (See 2009 SOM, Table 2-40)

Type/Fuel	2010
Transaction	38%
DEC	27%
INC	22%
Coal	9%
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 September 2010 (See 2009 SOM, Figure 2-6)



Unit Markup Characteristics

Table 2-46 Average, day-ahead marginal unit markup index (By primary fuel and unit type): January through September 2010 (See 2009 SOM, Table 2-41)

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	(0.07)	($2.51)
Diesel	Diesel	(0.24)	($16.12)
Municipal waste	Steam	0.00	$0.06
Natural gas	CT	0.07	$4.64
Natural gas	Diesel	(0.03)	($2.24)
Natural gas	Steam	0.01	$0.91
Oil	Steam	0.02	$4.67
Wind	Wind	0.00	$0.00

Table 2-47 Average, day-ahead marginal unit markup index (By price category): January through September 2010 (See 2009 SOM, Table 2-42)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.11)	($3.40)
$25 to $50	(0.05)	($2.18)
$50 to $75	0.03	$1.56
$75 to $100	0.14	$11.18
$100 to $125	0.01	$1.08
$125 to $150	0.26	$34.46
> $150	0.28	$54.75

Markup Component of System Price

Table 2-48 Monthly markup components of day-ahead, load-weighted LMP: January through September 2010 (See 2009 SOM, Table 2-43)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.42)	($0.12)	($0.67)
Feb	($0.52)	($0.27)	($0.79)
Mar	($1.46)	($0.92)	($2.10)
Apr	($1.23)	($0.74)	($1.83)
May	($0.72)	($0.09)	($1.31)
Jun	($0.47)	$0.14	($1.20)
Jul	$0.29	$1.49	($0.96)
Aug	($0.16)	$0.87	($1.37)
Sep	($1.17)	($0.54)	($1.89)
Annual	($0.60)	$0.04	($1.29)

Markup by System Price Levels

Table 2-49 Average, day-ahead markup (By price category): January through September 2010 (See 2009 SOM, Table 2-45)

	Average Markup Component	Frequency
Below $20	($2.85)	0%
$20 to $40	($2.22)	52%
$40 to $60	($0.22)	35%
$60 to $80	$0.66	8%
$80 to $100	$2.43	3%
$100 to $120	$2.34	1%
$120 to $140	$2.29	0%
$140 to $160	$21.36	0%
Above $160	($15.75)	0%

Markup Component by Fuel, Unit Type

Table 2-50 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September 2010 (See 2009 SOM, Table 2-46)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.72)	120.6%
Diesel	Diesel	($0.00)	0.8%
Municipal waste	Steam	$0.00	(0.0%)
Natural gas	CT	$0.03	(4.4%)
Natural gas	Diesel	($0.00)	0.3%
Natural gas	Steam	$0.09	(15.0%)
Oil	Steam	$0.01	(2.3%)
Wind	Wind	$0.00	0.0%
Total		($0.60)	100.0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-51 Frequently mitigated units and associated units (By month): January through September 2010 (See 2009 SOM, Table 2-47)

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
Jan	35	31	27	93
Feb	35	28	31	94
Mar	42	16	44	102
Apr	38	13	47	98
May	35	19	35	89
Jun	29	16	41	86
Jul	21	21	46	88
Aug	25	31	59	115
Sep	34	31	56	121

Table 2-52 Frequently mitigated units and associated units total months eligible: January through September 2010 (See 2009 SOM, Table 2-48)

Months Adder-Eligible	FMU & AU Count
Jan	25
Feb	18
Mar	8
Apr	6
May	11
Jun	9
Jul	12
Aug	10
Sep	56
Total	155

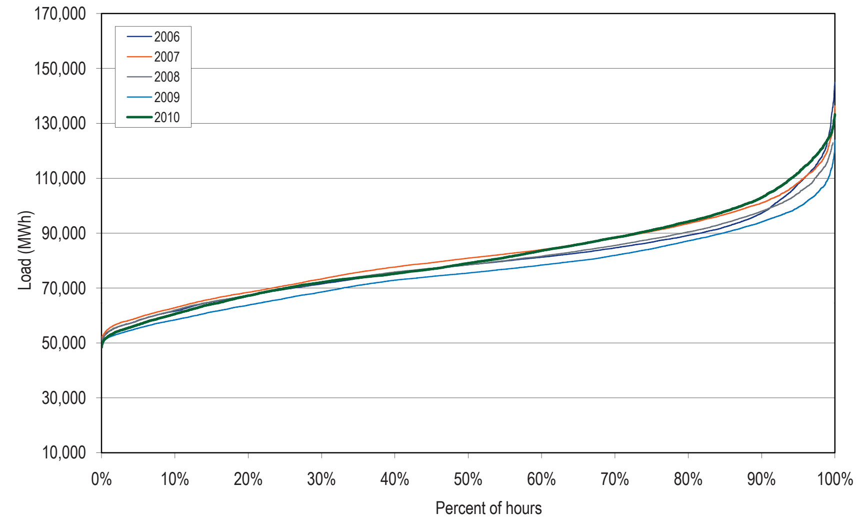
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

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



PJM Real-Time, Annual Average Load

Table 2-53 PJM real-time average load: Calendar years 1998 through September 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	81,068	79,053	16,209	6.6%	4.7%	22.2%

PJM Real-Time, Monthly Average Load

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

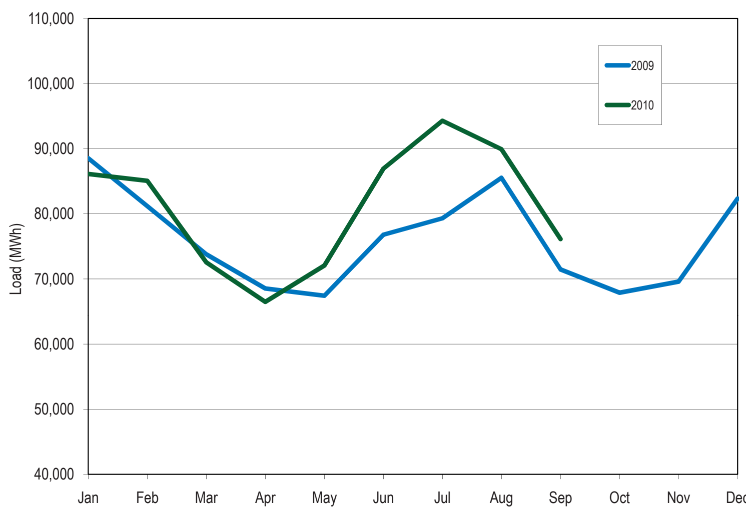


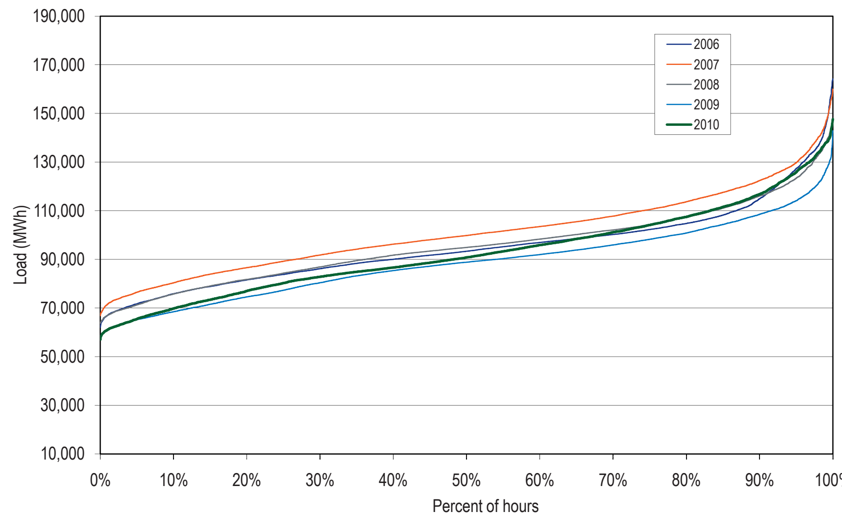
Table 2-54 PJM annual Summer THI, Winter WWP and average temperature: cooling, heating and shoulder months of 2006 through September 2010 (See 2009 SOM, Table 2-51)

	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	77.36	24.47	60.07

Day-Ahead Load

PJM Day-Ahead Load Duration

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



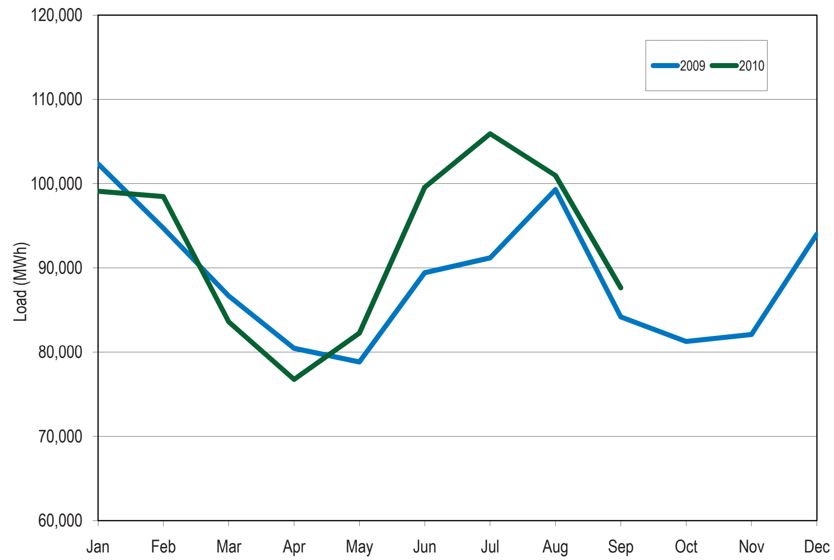
PJM Day-Ahead, Annual Average Load

Table 2-55 PJM day-ahead average load: Calendar years 2000 through September 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	92,683	90,804	17,769	4.5%	2.2%	19.3%

PJM Day-Ahead, Monthly Average Load

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



Real-Time and Day-Ahead Load

Table 2-56 Cleared day-ahead and real-time load (MWh): January through September 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	75,788	1,264	16,254	93,306	81,679	11,628	(4,627)
Median	73,674	1,156	16,185	91,223	79,548	11,674	(4,510)
Standard deviation	15,211	489	2,648	17,765	16,242	1,523	(1,125)
Peak average	84,175	1,459	17,641	103,275	90,300	12,975	(4,666)
Peak median	82,487	1,350	17,574	101,372	88,431	12,941	(4,634)
Peak standard deviation	13,548	485	2,169	15,381	14,612	769	(1,400)
Off peak average	68,454	1,094	15,042	84,590	74,141	10,449	(4,593)
Off peak median	67,006	1,007	14,837	82,793	72,651	10,142	(4,695)
Off peak standard deviation	12,567	425	2,425	14,896	13,639	1,257	(1,168)

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

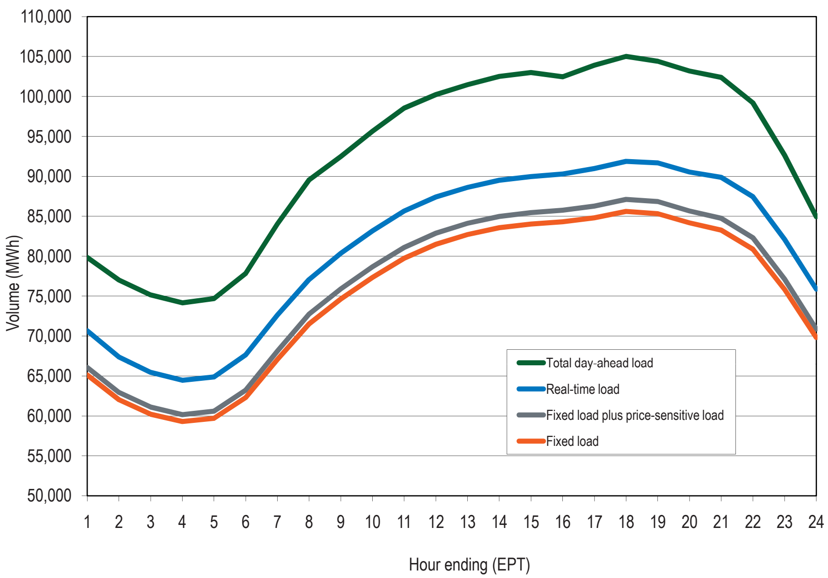
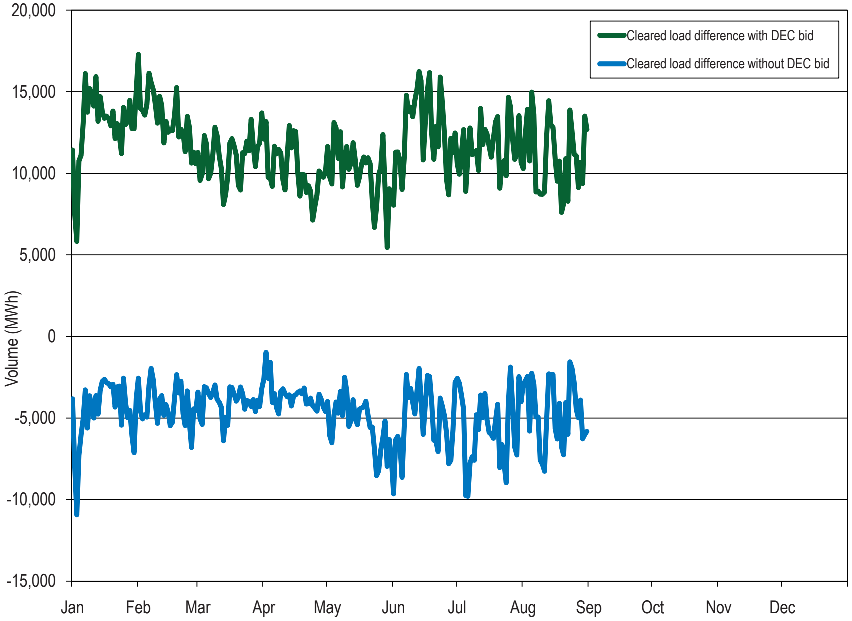


Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): January through September 2010 (New Figure)



Day-Ahead and Real-Time Generation

Table 2-57 Day-ahead and real-time generation (MWh): January through September 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	85,366	11,161	96,527	84,542	825	11,986
Median	83,486	11,023	94,448	82,508	978	11,940
Standard deviation	17,552	1,610	18,199	16,448	1,104	1,751
Peak average	94,654	12,011	106,665	93,019	1,636	13,647
Peak median	92,836	11,945	104,597	91,054	1,782	13,543
Peak standard deviation	15,294	1,486	15,766	14,772	522	993
Off peak average	77,246	10,417	87,663	77,130	116	10,533
Off peak median	75,849	10,420	85,949	75,881	(32)	10,067
Off peak standard deviation	15,217	1,321	15,332	14,091	1,127	1,241

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

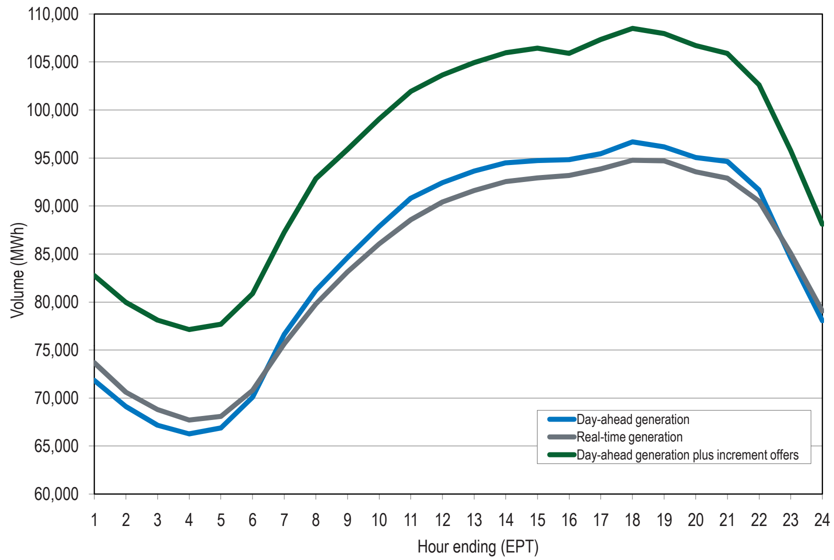
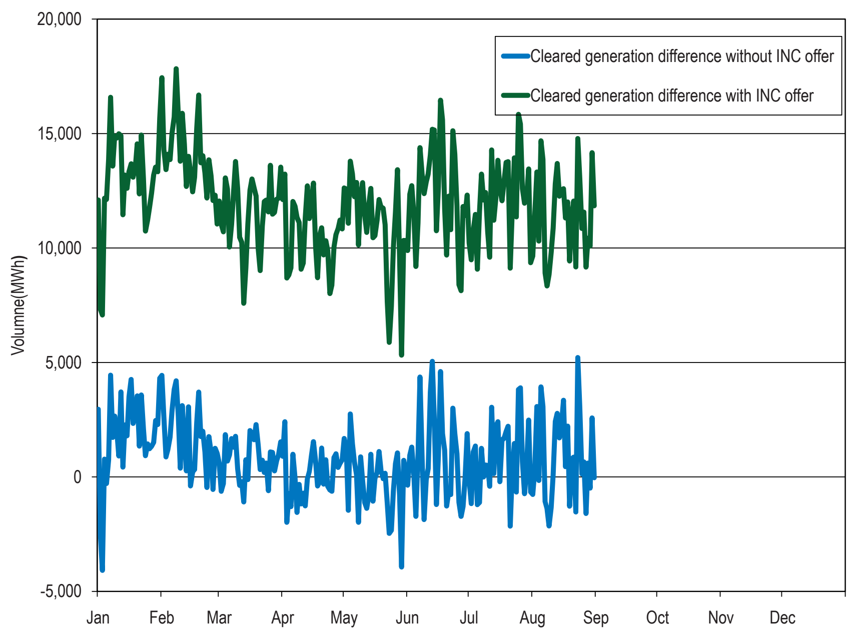


Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January through September 2010 (New Figure)



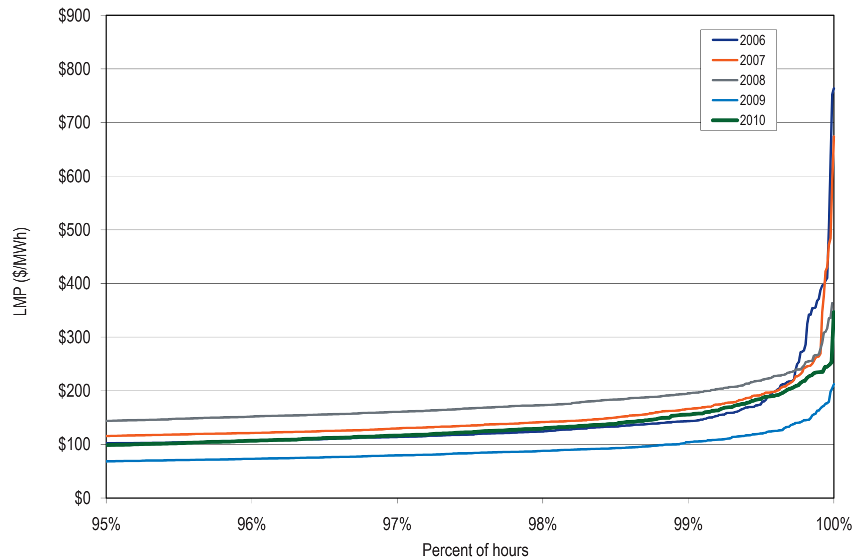
Locational Marginal Price (LMP)

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 September 2010 (See 2009 SOM, Figure 2-13)



PJM Real-Time, Annual Average LMP

Table 2-58 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 through September 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	$46.13	$37.89	$26.99	24.4%	15.8%	57.6%

Table 2-59 PJM real-time, simple average LMP (Dollars per MWh): January through September 2006, 2007, 2008, 2009 and 2010 (New Table)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2006 (Jan - Sep)	$51.79	$43.50	$34.93	NA	NA	NA
2007 (Jan - Sep)	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008 (Jan - Sep)	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009 (Jan - Sep)	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010 (Jan - Sep)	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%

Zonal Real-Time, Annual Average LMP

Table 2-60 Zonal real-time, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-56)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AECO	$41.33	$52.40	$11.07	26.8%
AEP	$33.81	$39.13	$5.32	15.7%
AP	$38.89	$45.30	$6.41	16.5%
BGE	$42.04	$55.05	$13.01	30.9%
ComEd	$28.78	$35.31	$6.53	22.7%
DAY	$33.56	$39.16	$5.60	16.7%
DLCO	$32.47	$38.17	$5.71	17.6%
Dominion	$40.55	$52.11	$11.56	28.5%
DPL	$42.02	$52.64	$10.62	25.3%
JCPL	$41.39	$51.17	$9.78	23.6%
Met-Ed	$40.40	$50.90	$10.50	26.0%
PECO	$40.51	$50.71	$10.20	25.2%
PENELEC	$37.13	$43.38	$6.25	16.8%
Pepco	$42.26	$54.04	$11.78	27.9%
PPL	$39.87	$49.23	$9.36	23.5%
PSEG	$41.88	$52.03	$10.14	24.2%
RECO	$40.85	$50.14	$9.29	22.7%
PJM	$37.42	$46.13	$8.70	23.3%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-61 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-57)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
Delaware	$41.56	$51.69	$10.13	24.4%
Illinois	$28.78	$35.31	$6.53	22.7%
Indiana	$33.26	$38.36	$5.10	15.3%
Kentucky	$33.63	$39.32	$5.69	16.9%
Maryland	$42.03	$54.51	$12.48	29.7%
Michigan	$34.48	$39.05	$4.57	13.3%
New Jersey	$41.65	$51.82	$10.17	24.4%
North Carolina	$39.56	$50.13	$10.56	26.7%
Ohio	$33.33	$38.47	$5.14	15.4%
Pennsylvania	$38.86	$47.32	$8.46	21.8%
Tennessee	$33.69	$40.06	$6.37	18.9%
Virginia	$39.83	$50.55	$10.73	26.9%
West Virginia	$35.03	$39.82	$4.80	13.7%
District of Columbia	$43.74	$54.21	$10.47	23.9%

Hub Real-Time, Annual Average LMP

Table 2-62 Hub real-time, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-58)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AEP Gen Hub	$31.90	$36.53	$4.64	14.5%
AEP-DAY Hub	$33.39	$38.48	$5.09	15.2%
Chicago Gen Hub	$27.98	$34.17	$6.19	22.1%
Chicago Hub	$28.98	$35.53	$6.55	22.6%
Dominion Hub	$39.88	$50.56	$10.68	26.8%
Eastern Hub	$41.97	$52.60	$10.63	25.3%
N Illinois Hub	$28.60	$35.06	$6.46	22.6%
New Jersey Hub	$41.61	$51.70	$10.09	24.2%
Ohio Hub	$33.39	$38.57	$5.18	15.5%
West Interface Hub	$34.73	$41.57	$6.84	19.7%
Western Hub	$38.64	$46.70	$8.06	20.9%

Real-Time, Load-Weighted, Average LMP

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

Table 2-63 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through September 2010 (See 2009 SOM, Table 2-59)

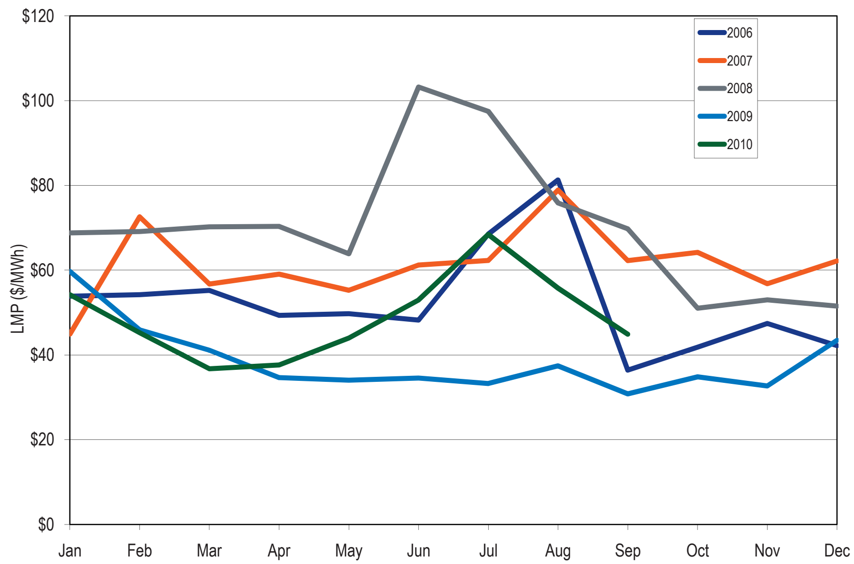
	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
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	$49.91	$40.33	$29.65	27.8%	17.8%	62.8%

Table 2-64 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2006, 2007, 2008, 2009 and 2010 (New Table)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2006 (Jan - Sep)	$56.39	$46.82	$40.70	NA	NA	NA
2007 (Jan - Sep)	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008 (Jan - Sep)	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009 (Jan - Sep)	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010 (Jan - Sep)	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%

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

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



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

Table 2-65 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-60)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AECO	$43.27	$59.51	$16.24	37.5%
AEP	$35.56	$41.37	$5.81	16.3%
AP	$41.49	$48.37	$6.88	16.6%
BGE	$44.83	$60.99	$16.16	36.0%
ComEd	$30.60	$38.46	$7.87	25.7%
DAY	$35.30	$41.82	$6.52	18.5%
DLCO	$33.65	$40.69	$7.04	20.9%
Dominion	$43.46	$57.51	$14.05	32.3%
DPL	$45.13	$58.42	$13.29	29.4%
JCPL	$43.78	$57.98	$14.20	32.4%
Met-Ed	$43.01	$55.45	$12.44	28.9%
PECO	$42.69	$55.59	$12.89	30.2%
PENELEC	$39.03	$45.58	$6.55	16.8%
Pepco	$45.10	$59.69	$14.59	32.3%
PPL	$42.83	$53.23	$10.40	24.3%
PSEG	$43.74	$57.37	$13.62	31.1%
RECO	$42.91	$56.61	$13.69	31.9%
PJM	$39.57	$49.91	$10.35	26.2%

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

Table 2-66 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-61)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
Delaware	$44.21	$57.03	$12.82	29.0%
Illinois	$30.60	$38.46	$7.87	25.7%
Indiana	$34.42	$40.11	$5.69	16.5%
Kentucky	$36.18	$41.92	$5.75	15.9%
Maryland	$45.12	$60.53	$15.41	34.2%
Michigan	$35.78	$41.72	$5.94	16.6%
New Jersey	$43.67	$57.83	$14.15	32.4%
North Carolina	$42.10	$55.17	$13.07	31.0%
Ohio	$34.92	$40.71	$5.79	16.6%
Pennsylvania	$41.12	$50.96	$9.84	23.9%
Tennessee	$35.88	$42.86	$6.97	19.4%
Virginia	$42.77	$55.53	$12.76	29.8%
West Virginia	$37.24	$42.08	$4.84	13.0%
District of Columbia	$46.29	$58.79	$12.51	27.0%

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

Fuel Cost

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

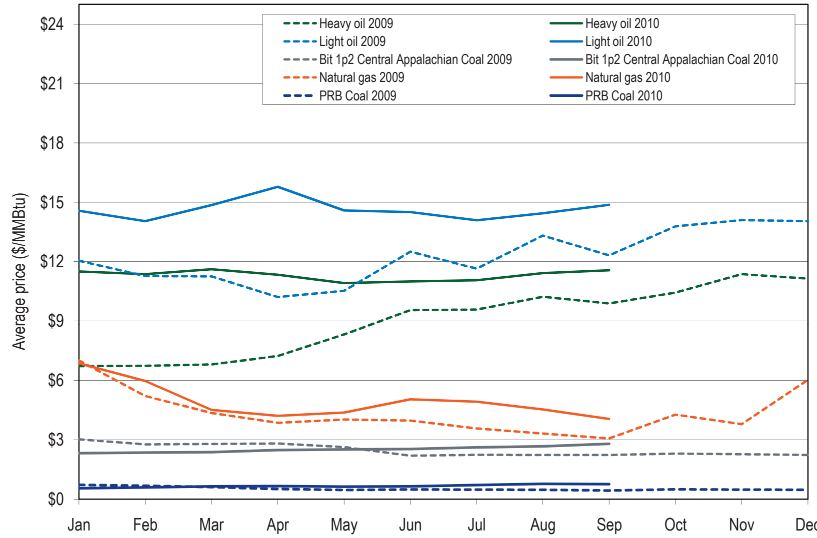


Figure 2-18 Spot average emission price comparison: Calendar years 2009 through September 2010 (See 2009 SOM, Figure 2-16)

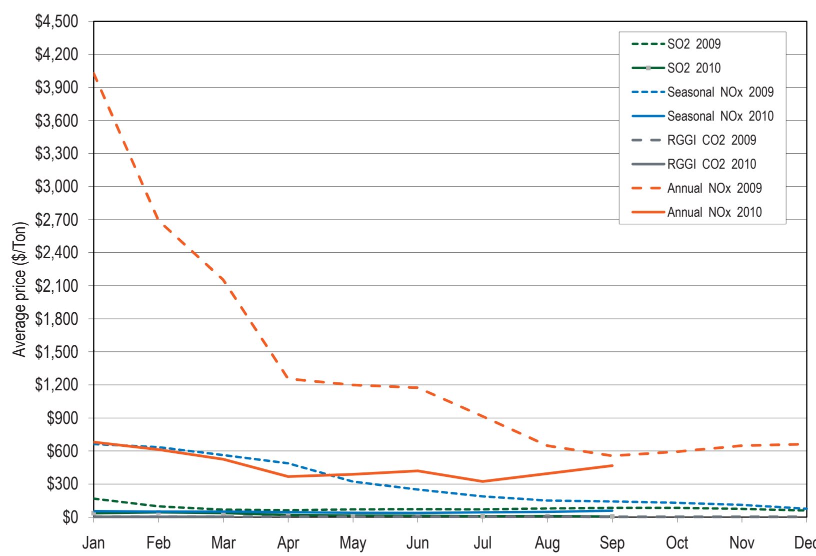


Table 2-67 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2009 SOM, Table 2-62)

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
September 10, 2010	$1.86	45,595,968	34,407,000

Table 2-68 PJM real-time annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-63)

	2010 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$49.91	$49.74	(0.3%)
	2009 Load-Weighted LMP	**2010 Fuel-Cost-Adjusted, Load-Weighted LMP**	**Change**
Average	$39.57	$49.74	25.7%
	2009 Load-Weighted LMP	**2010 Load-Weighted LMP**	**Change**
Average	$39.57	$49.91	26.2%

Components of Real-Time, Load-Weighted LMP

Table 2-69 Components of PJM real-time, annual, load-weighted, average LMP: January 1, 2010, through September 30, 2010 (See 2009 SOM, Table 2-64)

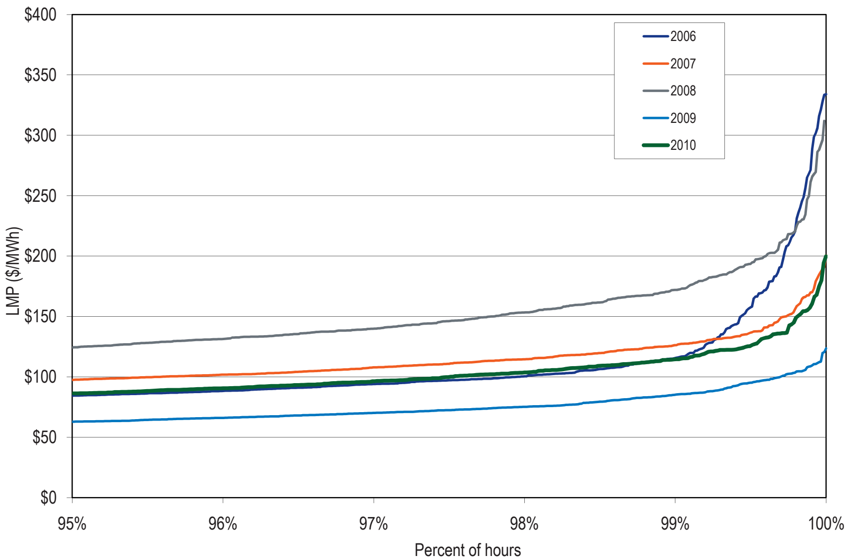
Element	Contribution to LMP	Percent
Gas	$20.03	40.1%
Coal	$18.81	37.7%
10% Cost Adder	$4.43	8.9%
VOM	$2.89	5.8%
Oil	$2.00	4.0%
NOx	$1.08	2.2%
CO2	$0.60	1.2%
Markup	$0.49	1.0%
NA	$0.35	0.7%
SO2	$0.18	0.4%
FMU Adder	$0.16	0.3%
M2M Adder	$0.01	0.0%
Shadow Price Limit Adder	$0.01	0.0%
Offline CT Adder	$0.00	0.0%
Unit LMP Differential	$0.00	0.0%
Municipal Waste	($0.00)	(0.0%)
UDS Override Differential	($0.54)	(1.1%)
Dispatch Differential	($0.58)	(1.2%)
LMP	$49.91	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 September 2010 (See 2009 SOM, Figure 2-17)



PJM Day-Ahead, Annual Average LMP

Table 2-70 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 through September 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	$45.81	$41.03	$19.59	23.8%	16.7%	46.4%

Table 2-71 PJM day-ahead, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (New Table)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2006 (Jan - Sep)	$50.45	$46.32	$24.93	NA	NA	NA
2007 (Jan - Sep)	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008 (Jan - Sep)	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009 (Jan - Sep)	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010 (Jan - Sep)	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%

Zonal Day-Ahead, Annual Average LMP

Table 2-72 Zonal day-ahead, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-66)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AECO	$42.15	$51.79	$9.64	22.9%
AEP	$33.70	$39.00	$5.30	15.7%
AP	$38.37	$45.16	$6.79	17.7%
BGE	$42.75	$54.65	$11.90	27.8%
ComEd	$28.80	$35.29	$6.49	22.5%
DAY	$33.07	$38.85	$5.78	17.5%
DLCO	$32.25	$38.90	$6.65	20.6%
Dominion	$41.07	$52.22	$11.15	27.1%
DPL	$42.43	$52.02	$9.59	22.6%
JCPL	$41.99	$51.29	$9.30	22.1%
Met-Ed	$40.87	$50.59	$9.72	23.8%
PECO	$41.37	$50.90	$9.52	23.0%
PENELEC	$37.46	$44.39	$6.93	18.5%
Pepco	$42.91	$54.25	$11.34	26.4%
PPL	$40.45	$49.05	$8.60	21.3%
PSEG	$42.56	$52.04	$9.48	22.3%
RECO	$41.51	$50.86	$9.35	22.5%
PJM	$37.35	$45.81	$8.46	22.7%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-73 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-67)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
Delaware	$41.81	$50.94	$9.13	21.8%
Illinois	$28.80	$35.29	$6.49	22.5%
Indiana	$33.14	$38.26	$5.12	15.4%
Kentucky	$33.41	$39.08	$5.67	17.0%
Maryland	$42.64	$54.46	$11.82	27.7%
Michigan	$34.41	$38.87	$4.46	13.0%
New Jersey	$42.33	$51.79	$9.46	22.4%
North Carolina	$40.03	$50.39	$10.36	25.9%
Ohio	$33.00	$38.20	$5.19	15.7%
Pennsylvania	$39.29	$47.46	$8.18	20.8%
Tennessee	$33.90	$40.05	$6.14	18.1%
Virginia	$40.37	$50.86	$10.50	26.0%
West Virginia	$34.80	$39.69	$4.89	14.1%
District of Columbia	$44.06	$54.28	$10.22	23.2%

Day-Ahead, Load-Weighted, Average LMP

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

Table 2-74 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through September 2010 (See 2009 SOM, Table 2-68)

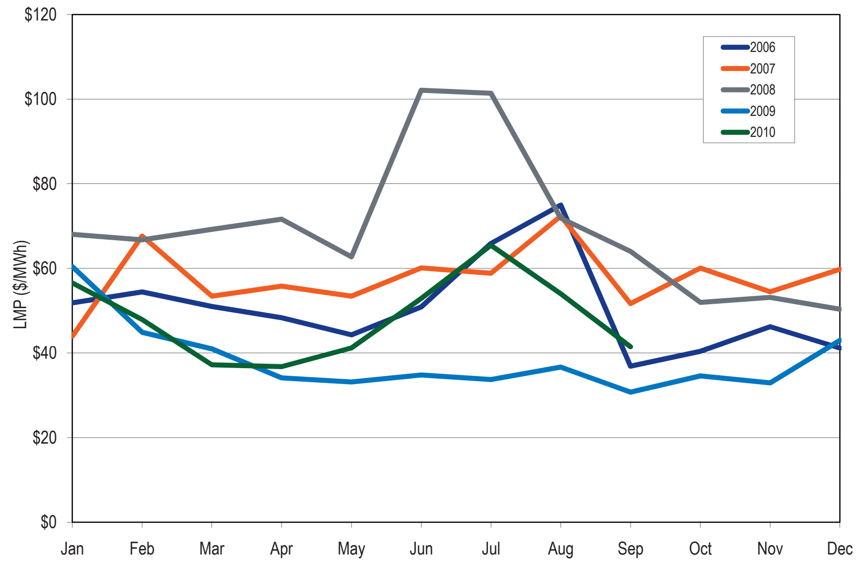
	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
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	$49.12	$43.33	$21.35	26.5%	18.2%	52.2%

Table 2-75 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September 2006, 2007, 2008, 2009 to 2010 (New Table)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2006 (Jan - Sep)	$54.19	$48.87	$28.35	NA	NA	NA
2007 (Jan - Sep)	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008 (Jan - Sep)	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009 (Jan - Sep)	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010 (Jan - Sep)	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%

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

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



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-76 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through September 2009 to 2010 (See 2009 SOM, Table 2-69)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
AECO	$44.48	$59.13	$14.65	32.9%
AEP	$35.37	$41.23	$5.87	16.6%
AP	$40.77	$47.83	$7.06	17.3%
BGE	$45.38	$60.25	$14.87	32.8%
ComEd	$30.11	$37.68	$7.58	25.2%
DAY	$34.63	$41.31	$6.69	19.3%
DLCO	$33.33	$41.37	$8.05	24.2%
Dominion	$43.87	$57.37	$13.49	30.8%
DPL	$45.11	$57.37	$12.26	27.2%
JCPL	$44.22	$56.70	$12.48	28.2%
Met-Ed	$43.54	$54.68	$11.14	25.6%
PECO	$43.49	$55.30	$11.81	27.2%
PENELEC	$39.06	$46.03	$6.97	17.8%
Pepco	$45.43	$57.89	$12.46	27.4%
PPL	$43.14	$52.44	$9.30	21.6%
PSEG	$44.48	$56.46	$11.98	26.9%
RECO	$43.93	$57.14	$13.21	30.1%
PJM	$39.35	$49.12	$9.77	24.8%

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

Table 2-77 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-70)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Difference	Difference as Percent of 2009
Delaware	$44.31	$55.79	$11.48	25.9%
Illinois	$30.11	$37.68	$7.58	25.2%
Indiana	$34.23	$40.24	$6.01	17.6%
Kentucky	$35.77	$41.42	$5.65	15.8%
Maryland	$45.41	$59.30	$13.89	30.6%
Michigan	$35.58	$40.56	$4.97	14.0%
New Jersey	$44.38	$56.88	$12.49	28.2%
North Carolina	$42.71	$55.39	$12.68	29.7%
Ohio	$34.56	$40.36	$5.80	16.8%
Pennsylvania	$41.36	$50.45	$9.09	22.0%
Tennessee	$35.96	$42.64	$6.68	18.6%
Virginia	$43.12	$55.60	$12.48	29.0%
West Virginia	$36.74	$42.06	$5.32	14.5%
District of Columbia	$46.86	$57.59	$10.72	22.9%

Components of Day-Ahead, Load-Weighted LMP

Table 2-78 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-71)

Element	Contribution to LMP	Percent
INC	$18.42	37.5%
DEC	$13.14	26.7%
Coal	$6.98	14.2%
Natural gas	$5.83	11.9%
Transaction	$1.52	3.1%
10% Cost offer	$1.45	2.9%
VOM	$0.83	1.7%
Price sensitive demand	$0.70	1.4%
NOx	$0.35	0.7%
CO2	$0.22	0.4%
Oil	$0.17	0.4%
Constrained off	$0.12	0.2%
SO2	$0.06	0.1%
Diesel	$0.01	0.0%
FMU adder	$0.00	0.0%
Markup	($0.60)	(1.2%)
NA	($0.09)	(0.2%)
Total	$49.12	100.0%

Marginal Losses

Table 2-79 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through September 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	$46.13	$46.03	$0.06	$0.04

Table 2-80 Zonal real-time, simple average LMP components (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-73)

	2009 (Jan - Sep)				2010 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$41.33	$37.35	$2.13	$1.85	$52.40	$46.03	$3.87	$2.50
AEP	$33.81	$37.35	($2.32)	($1.23)	$39.13	$46.03	($5.23)	($1.66)
AP	$38.89	$37.35	$1.62	($0.08)	$45.30	$46.03	($0.42)	($0.31)
BGE	$42.04	$37.35	$3.05	$1.65	$55.05	$46.03	$6.72	$2.30
ComEd	$28.78	$37.35	($6.24)	($2.33)	$35.31	$46.03	($7.87)	($2.84)
DAY	$33.56	$37.35	($2.99)	($0.80)	$39.16	$46.03	($5.92)	($0.95)
DLCO	$32.47	$37.35	($3.53)	($1.35)	$38.17	$46.03	($6.08)	($1.78)
Dominion	$40.55	$37.35	$2.60	$0.60	$52.11	$46.03	$5.31	$0.78
DPL	$42.02	$37.35	$2.67	$2.00	$52.64	$46.03	$3.99	$2.63
JCPL	$41.39	$37.35	$2.11	$1.93	$51.17	$46.03	$2.79	$2.35
Met-Ed	$40.40	$37.35	$2.21	$0.83	$50.90	$46.03	$3.78	$1.09
PECO	$40.51	$37.35	$1.88	$1.28	$50.71	$46.03	$2.99	$1.69
PENELEC	$37.13	$37.35	($0.04)	($0.17)	$43.38	$46.03	($2.36)	($0.29)
Pepco	$42.26	$37.35	$3.82	$1.09	$54.04	$46.03	$6.61	$1.40
PPL	$39.87	$37.35	$1.90	$0.63	$49.23	$46.03	$2.38	$0.82
PSEG	$41.88	$37.35	$2.53	$2.01	$52.03	$46.03	$3.59	$2.41
RECO	$40.85	$37.35	$1.73	$1.77	$50.14	$46.03	$2.04	$2.08

Table 2-81 Hub real-time, simple average LMP components (Dollars per MWh): January through September 2010 (See 2009 SOM, 2-74)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$36.53	$46.03	($6.29)	($3.21)
AEP-DAY Hub	$38.48	$46.03	($5.70)	($1.85)
Chicago Gen Hub	$34.17	$46.03	($8.40)	($3.46)
Chicago Hub	$35.53	$46.03	($7.67)	($2.82)
Dominion Hub	$50.56	$46.03	$4.29	$0.25
Eastern Hub	$52.60	$46.03	$3.76	$2.82
N Illinois Hub	$35.06	$46.03	($7.89)	($3.08)
New Jersey Hub	$51.70	$46.03	$3.32	$2.35
Ohio Hub	$38.57	$46.03	($5.69)	($1.76)
West Interface Hub	$41.57	$46.03	($2.85)	($1.60)
Western Hub	$46.70	$46.03	$1.01	($0.34)

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

Table 2-82 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-75)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$59.51	$51.05	$5.58	$2.88
AEP	$41.37	$49.05	($5.91)	($1.78)
AP	$48.37	$49.35	($0.62)	($0.36)
BGE	$60.99	$50.23	$8.21	$2.54
ComEd	$38.46	$49.58	($8.19)	($2.93)
DAY	$41.82	$49.64	($6.86)	($0.96)
DLCO	$40.69	$49.52	($6.89)	($1.94)
Dominion	$57.51	$50.39	$6.29	$0.83
DPL	$58.42	$50.68	$4.78	$2.96
JCPL	$57.98	$51.43	$3.91	$2.64
Met-Ed	$55.45	$49.69	$4.57	$1.18
PECO	$55.59	$49.98	$3.75	$1.85
PENELEC	$45.58	$48.62	($2.72)	($0.33)
Pepco	$59.69	$50.30	$7.89	$1.51
PPL	$53.23	$49.43	$2.91	$0.89
PSEG	$57.37	$50.32	$4.43	$2.62
RECO	$56.61	$51.42	$2.88	$2.31
PJM	$49.91	$49.81	$0.06	$0.04

Table 2-83 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 through September 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	$45.81	$45.76	$0.08	($0.03)

Table 2-84 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through September 2009 and 2010 (See 2009 SOM, Table 2-77)

	2009 (Jan - Sep)				2010 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$42.15	$37.52	$2.35	$2.29	$51.79	$45.76	$2.96	$3.07
AEP	$33.70	$37.52	($2.24)	($1.58)	$39.00	$45.76	($4.41)	($2.35)
AP	$38.37	$37.52	$0.83	$0.03	$45.16	$45.76	($0.28)	($0.31)
BGE	$42.75	$37.52	$3.24	$2.00	$54.65	$45.76	$5.90	$2.99
ComEd	$28.80	$37.52	($5.61)	($3.11)	$35.29	$45.76	($6.63)	($3.85)
DAY	$33.07	$37.52	($3.01)	($1.44)	$38.85	$45.76	($5.01)	($1.90)
DLCO	$32.25	$37.52	($3.73)	($1.54)	$38.90	$45.76	($4.69)	($2.16)
Dominion	$41.07	$37.52	$2.59	$0.97	$52.22	$45.76	$5.13	$1.33
DPL	$42.43	$37.52	$2.58	$2.33	$52.02	$45.76	$3.20	$3.06
JCPL	$41.99	$37.52	$2.07	$2.41	$51.29	$45.76	$2.43	$3.10
Met-Ed	$40.87	$37.52	$2.33	$1.03	$50.59	$45.76	$3.41	$1.42
PECO	$41.37	$37.52	$2.10	$1.76	$50.90	$45.76	$2.73	$2.41
PENELEC	$37.46	$37.52	$0.01	($0.06)	$44.39	$45.76	($1.32)	($0.05)
Pepco	$42.91	$37.52	$3.78	$1.61	$54.25	$45.76	$6.29	$2.20
PPL	$40.45	$37.52	$2.12	$0.81	$49.05	$45.76	$2.26	$1.03
PSEG	$42.56	$37.52	$2.45	$2.59	$52.04	$45.76	$2.96	$3.32
RECO	$41.51	$37.52	$1.69	$2.30	$50.86	$45.76	$2.16	$2.93

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

Table 2-85 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-78)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$59.13	$51.39	$4.01	$3.73
AEP	$41.23	$48.81	($5.05)	($2.53)
AP	$47.83	$48.61	($0.43)	($0.36)
BGE	$60.25	$49.84	$7.07	$3.35
ComEd	$37.68	$48.55	($6.86)	($4.01)
DAY	$41.31	$49.09	($5.76)	($2.01)
DLCO	$41.37	$48.88	($5.16)	($2.35)
Dominion	$57.37	$49.84	$6.09	$1.44
DPL	$57.37	$50.15	$3.78	$3.44
JCPL	$56.70	$50.23	$3.04	$3.43
Met-Ed	$54.68	$49.12	$4.03	$1.53
PECO	$55.30	$49.40	$3.25	$2.65
PENELEC	$46.03	$47.59	($1.50)	($0.06)
Pepco	$57.89	$48.52	$7.02	$2.36
PPL	$52.44	$48.76	$2.56	$1.12
PSEG	$56.46	$49.47	$3.41	$3.59
RECO	$57.14	$51.16	$2.72	$3.26
PJM	$49.12	$49.05	$0.11	($0.03)

Marginal Loss Accounting

Monthly Marginal Loss Costs

Table 2-86 Marginal loss costs by type (Dollars (Millions)): January through September 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
Jul	$39.0	($180.9)	$12.0	$231.9	$1.5	($0.7)	($6.2)	($4.0)	$227.9
Aug	$16.0	($144.7)	$8.5	$169.2	$1.9	$0.5	($3.3)	($1.9)	$167.3
Sep	$11.7	($95.8)	$7.6	$115.2	$0.5	($0.6)	($3.2)	($2.0)	$113.1
Total	$219.5	($993.2)	$61.5	$1,274.2	$9.0	($6.0)	($30.0)	($15.0)	$1,259.2

Zonal Marginal Loss Costs

Table 2-87 Marginal loss costs by control zone and type (Dollars (Millions)): January through September 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	$30.6	$7.8	$0.2	$23.1	$1.4	($0.5)	($0.1)	$1.8	$24.8
AEP	($66.7)	($303.0)	$18.0	$254.2	$4.0	$3.9	($1.5)	($1.4)	$252.8
AP	($10.6)	($101.8)	$8.9	$100.1	$3.2	$5.0	($4.5)	($6.3)	$93.7
BGE	$71.8	$20.7	$3.3	$54.4	$4.3	($2.5)	($2.6)	$4.2	$58.6
ComEd	($183.8)	($405.9)	$3.9	$226.0	($7.9)	($2.7)	($2.9)	($8.1)	$217.9
DAY	($4.6)	($53.5)	$13.3	$62.1	$0.1	$1.3	($10.9)	($12.1)	$50.0
DLCO	($30.5)	($48.1)	$0.2	$17.7	($2.4)	($0.3)	($0.1)	($2.3)	$15.5
Dominion	$91.5	($48.7)	$7.1	$147.4	$3.0	($0.4)	($3.2)	$0.2	$147.5
DPL	$53.3	$11.1	$0.7	$42.9	($2.5)	($1.6)	($0.5)	($1.4)	$41.5
JCPL	$63.5	$24.3	$0.3	$39.5	$0.2	($1.1)	($0.3)	$1.0	$40.5
Met-Ed	$18.8	$3.0	$0.1	$15.9	$0.0	($0.2)	($0.1)	$0.2	$16.0
PECO	$65.9	$22.0	$0.2	$44.1	($1.1)	($0.5)	($0.1)	($0.7)	$43.4
PENELEC	($24.1)	($84.7)	($0.0)	$60.5	$3.8	($2.7)	$0.2	$6.7	$67.2
Pepco	$93.1	$41.2	$2.7	$54.6	($2.5)	($1.0)	($1.8)	($3.3)	$51.3
PJM	($84.4)	($102.3)	($8.1)	$9.7	$2.1	($9.7)	$6.1	$17.9	$27.6
PPL	$33.2	($11.6)	$1.3	$46.1	$2.1	$1.0	$0.1	$1.2	$47.2
PSEG	$99.2	$35.9	$9.5	$72.8	$0.9	$6.2	($7.8)	($13.1)	$59.7
RECO	$3.4	$0.3	$0.0	$3.1	$0.4	($0.2)	($0.0)	$0.6	$3.7
Total	$219.5	($993.2)	$61.5	$1,274.2	$9.0	($6.0)	($30.0)	($15.0)	$1,259.2

Table 2-88 Monthly marginal loss costs by control zone (Dollars (Millions)): January through September 2010 (See 2009 SOM, Table 2-81)

	Marginal Loss Costs by Control Zone (Millions)									
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Grand Total
AECO	$2.6	$1.5	$1.4	$1.4	$1.6	$3.3	$6.7	$4.1	$2.1	$24.8
AEP	$40.0	$25.9	$16.4	$13.8	$14.8	$31.5	$53.5	$37.8	$19.2	$252.8
AP	$13.7	$11.2	$6.8	$6.5	$8.4	$11.3	$16.7	$12.0	$6.9	$93.7
BGE	$8.8	$6.7	$3.7	$3.3	$4.8	$7.3	$11.3	$7.8	$5.0	$58.6
ComEd	$36.1	$23.9	$19.8	$16.2	$16.9	$23.7	$32.0	$26.4	$23.0	$217.9
DAY	$6.6	$5.3	$4.2	$2.6	$4.6	$5.6	$9.7	$6.7	$4.6	$50.0
DLCO	$3.0	$2.3	$1.6	$1.3	$1.4	$1.5	$1.7	$1.3	$1.3	$15.5
Dominion	$20.1	$15.9	$9.0	$8.9	$10.8	$21.0	$28.6	$20.2	$13.1	$147.5
DPL	$5.7	$3.6	$2.6	$2.8	$3.2	$4.7	$8.5	$6.0	$4.4	$41.5
JCPL	$6.3	$4.0	$3.3	$2.3	$3.3	$5.1	$8.2	$4.9	$3.0	$40.5
Met-Ed	$2.8	$1.6	$1.4	$1.0	$1.4	$2.1	$2.3	$2.1	$1.3	$16.0
PECO	$4.2	$3.7	$2.3	$1.9	$3.6	$7.1	$9.3	$6.9	$4.4	$43.4
PENELEC	$10.4	$7.2	$3.6	$3.6	$5.8	$8.6	$11.1	$8.9	$8.0	$67.2
Pepco	$6.7	$5.7	$4.5	$3.8	$5.0	$6.4	$9.1	$6.0	$4.2	$51.3
PJM	$5.5	$3.7	$2.9	$2.4	$5.2	$3.2	$1.6	$1.8	$1.2	$27.6
PPL	$8.8	$6.3	$3.7	$2.2	$3.2	$5.4	$6.2	$6.3	$5.2	$47.2
PSEG	$7.0	$5.4	$5.8	$4.3	$5.3	$7.9	$10.4	$7.7	$5.8	$59.7
RECO	$0.5	$0.2	$0.2	$0.2	$0.3	$0.5	$0.8	$0.5	$0.4	$3.7
Total	$188.9	$134.3	$93.4	$78.4	$99.6	$156.3	$227.9	$167.3	$113.1	$1,259.2

Virtual Offers and Bids

Table 2-89 Monthly volume of cleared and submitted INCs, DECs: January through September 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	11,276	23,414	250	1,585	17,223	25,690	304	1,284
Aug	10,567	20,751	226	1,332	15,656	21,745	327	1,140
Sep	10,944	21,365	263	1,232	15,522	22,646	311	1,072
Oct								
Nov								
Dec								
Annual	11,137	21,611	274	1,134	16,174	25,539	273	976

Table 2-90 Type of day-ahead marginal units: January through September 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%
Jul	12.5%	40.7%	24.3%	21.7%	0.9%
Aug	11.1%	52.5%	17.7%	17.8%	0.9%
Sep	12.6%	43.8%	23.2%	18.4%	0.4%
Annual	12.9%	37.4%	27.3%	21.7%	0.6%

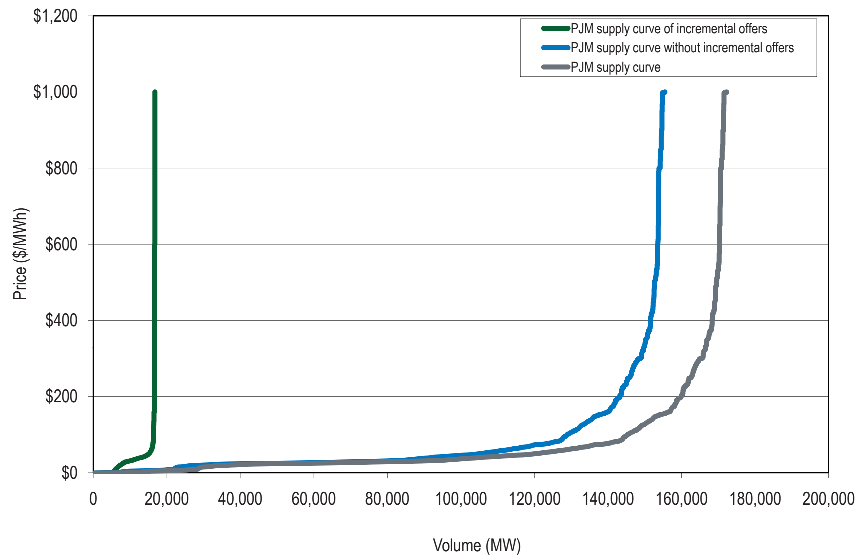
Table 2-91 PJM virtual bids by type of bid parent organization (MW): January through September 2010 (See 2009 SOM, Table 2-84)

	Category	Total Virtual Bids MW	Percentage
2010	Financial	98,859,787	32.0%
2010	Physical	210,016,261	68.0%
2010	Total	308,876,049	100.0%

Table 2-92 PJM virtual bids by top ten locations (MW): January through September 2010 (See 2009 SOM, Table 2-85)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	45,935,725	52,987,976	98,923,702
N ILLINOIS HUB	HUB	8,130,610	8,302,430	16,433,040
AEP-DAYTON HUB	HUB	4,500,957	5,745,609	10,246,566
PSEG	ZONE	2,099,900	4,656,424	6,756,324
PPL	ZONE	395,988	6,247,001	6,642,988
Pepco	ZONE	5,157,391	1,000,756	6,158,147
BGE	ZONE	3,175,589	2,702,532	5,878,121
JCPL	ZONE	3,412,010	2,038,140	5,450,150
MISO	INTERFACE	1,040,035	2,811,361	3,851,396
ComEd	ZONE	1,607,186	1,460,892	3,068,078

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



Price Convergence

Table 2-93 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-86)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$45.81	$46.13	$0.32	0.7%
Median	$41.03	$37.89	($3.14)	(8.3%)
Standard deviation	$19.59	$26.99	$7.39	27.4%

Table 2-94 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 through September 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	$45.81	$46.13	$0.32	0.7%

Table 2-95 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2006 through September 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%	13	0.20%
($50) to $0	5,205	59.54%	4,600	52.89%	5,120	59.30%	5,108	58.34%	4,091	62.65%
$0 to $50	3,372	98.04%	3,827	96.58%	3,247	96.27%	3,603	99.47%	2,288	97.57%
$50 to $100	152	99.77%	255	99.49%	284	99.50%	41	99.94%	130	99.56%
$100 to $150	9	99.87%	31	99.84%	37	99.92%	5	100.00%	20	99.86%
$150 to $200	4	99.92%	5	99.90%	4	99.97%	0	100.00%	8	99.98%
$200 to $250	1	99.93%	1	99.91%	2	99.99%	0	100.00%	1	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 September 2010 (See 2009 SOM, Figure 2-20)

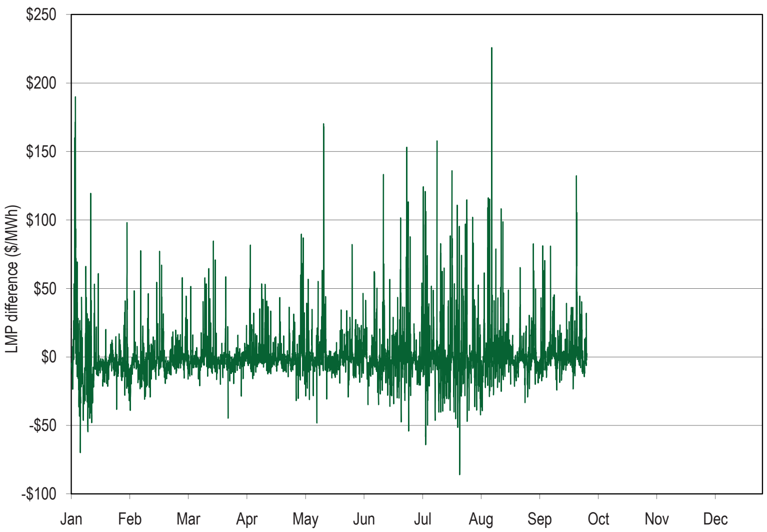


Figure 2-23 Monthly simple average of real-time minus day-ahead LMP: January through September 2010 (See 2009 SOM, Figure 2-21)

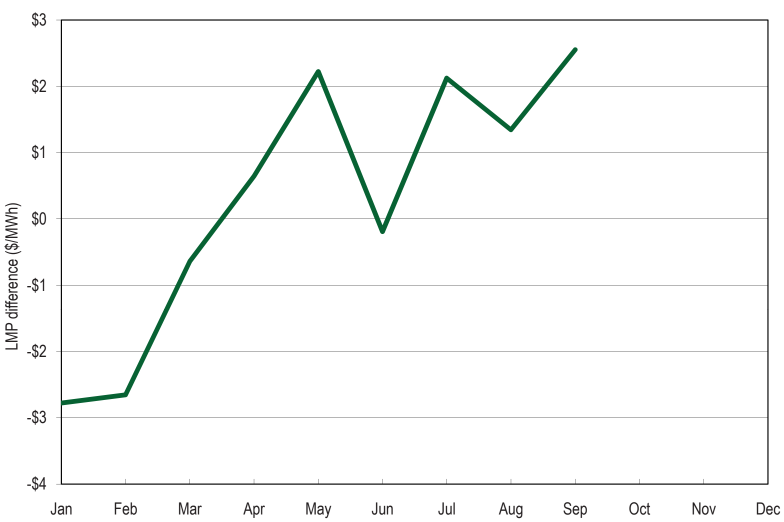
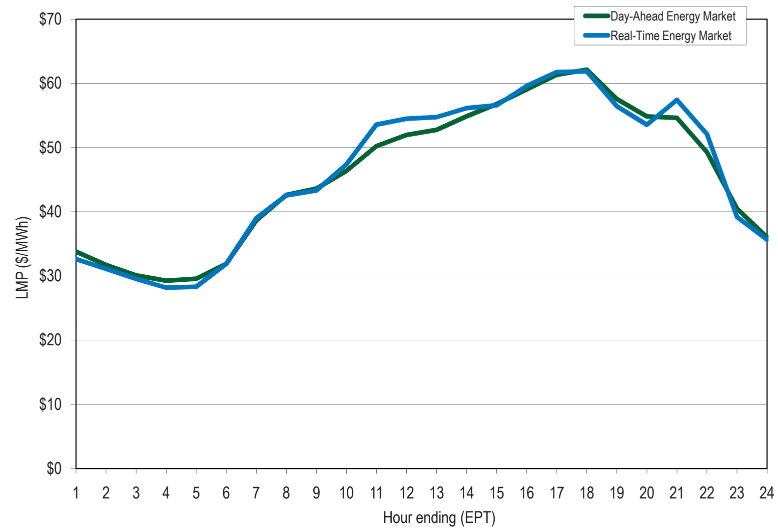


Figure 2-24 PJM system simple hourly average LMP: January through September 2010 (See 2009 SOM, Figure 2-22)



Zonal Price Convergence

Table 2-96 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-89)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$51.79	$52.40	$0.61	1.2%
AEP	$39.00	$39.13	$0.13	0.3%
AP	$45.16	$45.30	$0.13	0.3%
BGE	$54.65	$55.05	$0.40	0.7%
ComEd	$35.29	$35.31	$0.03	0.1%
DAY	$38.85	$39.16	$0.31	0.8%
DLCO	$38.90	$38.17	($0.73)	(1.9%)
Dominion	$52.22	$52.11	($0.11)	(0.2%)
DPL	$52.02	$52.64	$0.62	1.2%
JCPL	$51.29	$51.17	($0.12)	(0.2%)
Met-Ed	$50.59	$50.90	$0.31	0.6%
PECO	$50.90	$50.71	($0.19)	(0.4%)
PENELEC	$44.39	$43.38	($1.01)	(2.3%)
Pepco	$54.25	$54.04	($0.21)	(0.4%)
PPL	$49.05	$49.23	$0.17	0.4%
PSEG	$52.04	$52.03	($0.01)	(0.0%)
RECO	$50.86	$50.14	($0.71)	(1.4%)

Price Convergence by Jurisdiction

Table 2-97 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through September 2010 (See 2009 SOM, Table 2-90)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$50.94	$51.69	$0.76	1.5%
Illinois	$35.29	$35.31	$0.03	0.1%
Indiana	$38.26	$38.36	$0.09	0.2%
Kentucky	$39.08	$39.32	$0.24	0.6%
Maryland	$54.46	$54.51	$0.05	0.1%
Michigan	$38.87	$39.05	$0.18	0.5%
New Jersey	$51.79	$51.82	$0.03	0.1%
North Carolina	$50.39	$50.13	($0.26)	(0.5%)
Ohio	$38.20	$38.47	$0.27	0.7%
Pennsylvania	$47.46	$47.32	($0.14)	(0.3%)
Tennessee	$40.05	$40.06	$0.01	0.0%
Virginia	$50.86	$50.55	($0.31)	(0.6%)
West Virginia	$39.69	$39.82	$0.13	0.3%
District of Columbia	$54.28	$54.21	($0.07)	(0.1%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-98 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2009 to September 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%	9.8%	19.7%	70.6%	(2.8%)	2.7%	0.1%
Aug	11.7%	16.0%	72.3%	10.5%	20.7%	68.8%	(1.2%)	4.7%	(3.5%)
Sep	12.5%	18.1%	69.4%	12.0%	22.4%	65.6%	(0.5%)	4.3%	(3.8%)
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%	11.5%	19.4%	69.1%	(1.3%)	2.4%	(1.0%)

Day-Ahead Load and Spot Market

Table 2-99 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2009 to September 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%	4.7%	18.9%	76.5%	(0.9%)	2.9%	(1.9%)
Aug	5.2%	15.3%	79.5%	4.7%	19.6%	75.7%	(0.4%)	4.3%	(3.9%)
Sep	4.8%	16.1%	79.2%	4.5%	20.9%	74.6%	(0.2%)	4.8%	(4.6%)
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%	4.8%	18.9%	76.3%	(0.1%)	4.1%	(4.0%)

Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-100 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 2-101 Economic Program registration on peak load days: Calendar years 2002 to 2009 and January through September 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
06-Jul-10	899	1,725.7

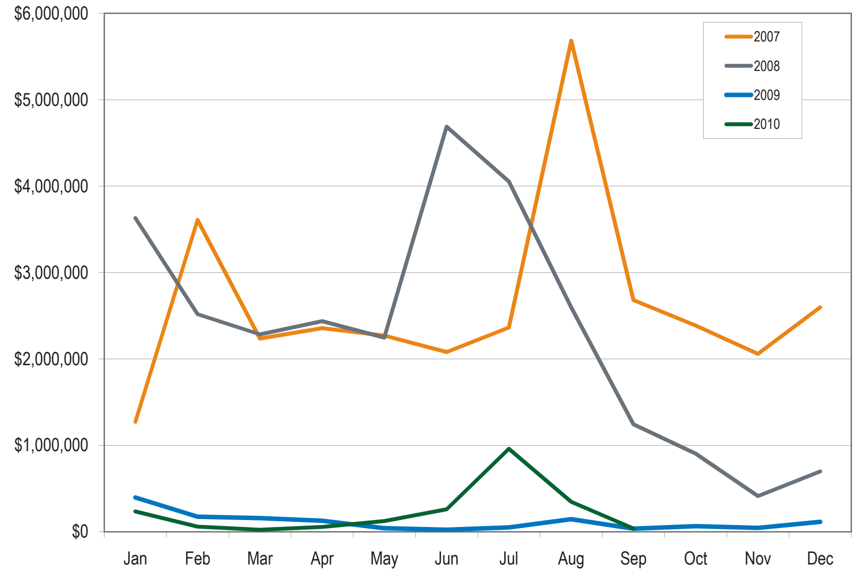
Table 2-102 Economic Program registrations on the last day of the month: January 2007 through September 2010 (See 2009 SOM, Table 2-95)

	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	2,587
May	996	3,674	5,069	3,588	1,250	2,860	1,875	2,587
Jun	2,490	2,168	3,112	3,014	1,265	2,461	813	1,608
Jul	2,872	2,459	4,542	3,165	1,265	2,445	1,192	2,159
Aug	2,911	2,582	4,815	3,232	1,653	2,650	1,616	2,398
Sep	4,868	2,915	4,836	3,263	1,879	2,727	1,849	2,587
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 2-103 Distinct registrations and sites in the Economic Program: July 6, 2010[13] (See 2009 SOM, Table 2-96)

	Registrations	Sites	MW
AECO	32	33	14.6
AEP	45	45	52.3
AP	53	55	185.0
BGE	62	63	476.0
ComEd	75	76	111.7
DAY	8	8	10.5
DLCO	89	89	199.3
Dominion	37	40	97.7
DPL	31	31	72.8
JCPL	40	43	100.9
Met-Ed	49	51	55.3
PECO	136	137	116.9
PENELEC	48	49	35.4
Pepco	26	26	26.9
PPL	114	119	144.3
PSEG	53	94	25.7
RECO	1	1	0.3
Total	899	960	1,725.7

Figure 2-25 Economic Program payments: Calendar years 2007[14] through 2009 and January through September 2010[15] (See 2009 SOM, Figure 2-24)



13 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.

14 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.

15 September 2010 credits and settlement counts 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 2-104 PJM Economic Program by zonal reduction: January through September 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	9	$406	8				78	$4,620	79	87	$5,026	87
AEP												
AP	3,555	$102,800	960				110	$11,535	39	3,665	$114,335	999
BGE	1,806	$300,724	251				1,873	$145,183	232	3,679	$445,908	483
ComEd	121	$3,614	121				2,166	$36,168	986	2,286	$39,782	1,107
DAY	0	$8	2				11	$1,165	1	11	$1,173	3
DLCO	9,627	$732,702	724	4,096	$98,936	212	953	$45,988	1,095	14,676	$877,626	2,031
Dominion	1	$248	10							1	$248	10
DPL												
JCPL	88	$15,426	16				35	$2,155	130	123	$17,581	146
Met-Ed	21	$310	22							21	$310	22
PECO	18,983	$543,396	17,020				455	$43,631	1,803	19,439	$587,027	18,823
PENELEC	20	$85	30				3	$273	14	23	$358	44
Pepco	28	$1,564	75				30	$1,542	132	58	$3,106	207
PPL	424	$11,273	408	3	$407	11	51	$3,558	225	478	$15,239	644
PSEG	61	$1,458	114							61	$1,458	114
RECO												
Total	34,744	$1,714,014	19,761	4,099	$99,343	223	5,766	$295,819	4,736	44,610	$2,109,176	24,720
Max	18,983	$732,702	17,020	4,096	$98,936	212	2,166	$145,183	1,803	19,439	$877,626	18,823
Avg	2,482	$122,430	1,412	2,050	$49,672	112	524	$26,893	431	3,186	$150,655	1,766

Table 2-105 Settlement days submitted by month in the Economic Program: January 2007 through September 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	673
Jun	1,856	3,184	2,727	1,221
Jul	2,534	3,339	2,879	3,007
Aug	3,962	3,848	3,760	2,158
Sep	3,388	3,264	2,570	660
Oct	3,508	1,977	2,361	
Nov	2,842	1,105	2,321	
Dec	2,675	986	1,240	
Total	26,423	32,990	21,605	10,437

Table 2-106 Distinct customers and CSPs submitting settlements in the Economic Program by month: January 2007 through September 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	6	140
Jun	12	195	17	317	20	231	11	152
Jul	15	259	16	295	21	183	18	243
Aug	19	321	17	306	15	400	14	302
Sep	15	279	17	312	11	181	11	97
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	24	433

Table 2-107 Hourly distribution of Economic Program MWh reductions and credits: January through September 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	280	0.63%	280	0.63%	$4,500	0.21%	$4,500	0.21%
2	299	0.67%	579	1.30%	$4,149	0.20%	$8,649	0.41%
3	348	0.78%	927	2.08%	$3,639	0.17%	$12,288	0.58%
4	360	0.81%	1,287	2.88%	$4,573	0.22%	$16,861	0.80%
5	390	0.87%	1,677	3.76%	$3,573	0.17%	$20,434	0.97%
6	423	0.95%	2,100	4.71%	$4,785	0.23%	$25,219	1.20%
7	1,027	2.30%	3,126	7.01%	$41,329	1.96%	$66,548	3.16%
8	1,634	3.66%	4,760	10.67%	$83,204	3.94%	$149,751	7.10%
9	1,838	4.12%	6,598	14.79%	$51,918	2.46%	$201,670	9.56%
10	1,705	3.82%	8,302	18.61%	$44,545	2.11%	$246,215	11.67%
11	1,605	3.60%	9,908	22.21%	$48,128	2.28%	$294,343	13.96%
12	1,743	3.91%	11,651	26.12%	$60,989	2.89%	$355,332	16.85%
13	2,018	4.52%	13,669	30.64%	$79,765	3.78%	$435,097	20.63%
14	2,545	5.70%	16,214	36.35%	$146,216	6.93%	$581,313	27.56%
15	4,209	9.44%	20,423	45.78%	$211,267	10.02%	$792,579	37.58%
16	4,678	10.49%	25,101	56.27%	$366,018	17.35%	$1,158,597	54.93%
17	5,075	11.38%	30,175	67.64%	$360,991	17.12%	$1,519,588	72.05%
18	4,991	11.19%	35,167	78.83%	$277,704	13.17%	$1,797,293	85.21%
19	2,465	5.53%	37,632	84.36%	$97,733	4.63%	$1,895,025	89.85%
20	1,876	4.21%	39,508	88.56%	$66,921	3.17%	$1,961,947	93.02%
21	1,556	3.49%	41,063	92.05%	$67,125	3.18%	$2,029,072	96.20%
22	1,507	3.38%	42,570	95.43%	$48,151	2.28%	$2,077,223	98.49%
23	1,164	2.61%	43,735	98.04%	$18,722	0.89%	$2,095,945	99.37%
24	875	1.96%	44,610	100.00%	$13,231	0.63%	$2,109,176	100.00%

Table 2-108 Distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through September 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	210	0.47%	210	0.47%	$232	0.01%	$232	0.01%
$25 to $50	15,977	35.82%	16,188	36.29%	$193,688	9.18%	$193,919	9.19%
$50 to $75	7,679	17.21%	23,866	53.50%	$200,571	9.51%	$394,491	18.70%
$75 to $100	4,648	10.42%	28,514	63.92%	$191,284	9.07%	$585,774	27.77%
$100 to $125	4,649	10.42%	33,163	74.34%	$193,193	9.16%	$778,968	36.93%
$125 to $150	3,968	8.89%	37,131	83.24%	$242,005	11.47%	$1,020,973	48.41%
$150 to $200	3,928	8.80%	41,059	92.04%	$401,654	19.04%	$1,422,626	67.45%
$200 to $250	1,437	3.22%	42,495	95.26%	$227,764	10.80%	$1,650,391	78.25%
$250 to $300	913	2.05%	43,408	97.31%	$154,887	7.34%	$1,805,278	85.59%
> $300	1,202	2.69%	44,610	100.00%	$303,899	14.41%	$2,109,176	100.00%

Emergency Program

Table 2-109 Registered sites and MW in the Emergency Program[16] (By zone and option): July 6, 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	7	12.1
AEP	0	0.0	688	1,039.1	164	674.9
AP	0	0.0	672	612.0	100	156.8
BGE	0	0.0	441	758.1	28	79.3
ComEd	0	0.0	899	949.9	582	513.5
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	33	84.6
DPL	0	0.0	174	140.8	18	36.8
JCPL	0	0.0	206	161.0	17	15.2
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	29	13.8
Pepco	0	0.0	265	177.8	27	33.8
PPL	0	0.0	643	671.2	84	56.1
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	1,472	1,999.9

Table 2-110 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	893.4	7,982.4	8,875.9

16 Table 2-109 shows registered sites and MW in the Emergency Program as of July 6, 2010, the peak load day through the first nine 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 2-110 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 2-111 Zonal monthly capacity credits: January 1, 2010 through September 30, 2010 (See 2009 SOM, Table 2-106)

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$538,827	$486,683	$387,589	$521,446	$538,827	$498,630	$515,251	$515,251	$498,630	$4,501,133
AEP	$3,871,619	$3,496,946	$3,871,619	$3,746,728	$3,871,619	$7,469,753	$7,718,744	$7,718,744	$7,469,753	$49,235,524
APS	$3,380,342	$3,053,212	$3,082,016	$3,271,298	$3,380,342	$4,134,986	$4,272,819	$4,272,819	$4,134,986	$32,982,821
BGE	$4,971,814	$4,490,671	$4,613,517	$4,811,433	$4,971,814	$4,877,253	$5,039,828	$5,039,828	$4,877,253	$43,693,412
ComEd	$4,423,355	$3,995,288	$4,357,876	$4,280,666	$4,423,355	$7,893,843	$8,156,971	$8,156,971	$7,893,843	$53,582,167
DAY	$667,966	$603,324	$667,966	$646,419	$667,966	$1,114,399	$1,151,545	$1,151,545	$1,114,399	$7,785,530
DLCO	$387,642	$350,129	$387,642	$375,138	$387,642	$1,082,462	$1,118,544	$1,118,544	$1,082,462	$6,290,206
Dominion	$1,655,820	$1,495,580	$1,655,820	$1,602,407	$1,655,820	$5,271,768	$5,447,494	$5,447,494	$5,271,768	$29,503,972
DPL	$1,117,919	$1,009,733	$1,004,045	$1,081,857	$1,117,919	$1,053,129	$1,088,233	$1,088,233	$1,053,129	$9,614,195
JCPL	$1,374,149	$1,241,167	$897,896	$1,329,822	$1,374,149	$1,259,066	$1,301,034	$1,301,034	$1,259,066	$11,337,383
Met-Ed	$1,357,392	$1,226,031	$1,357,392	$1,313,605	$1,357,392	$1,166,215	$1,205,089	$1,205,089	$1,166,215	$11,354,420
PECO	$2,717,550	$2,454,561	$2,120,899	$2,629,887	$2,717,550	$2,735,060	$2,826,229	$2,826,229	$2,735,060	$23,763,024
PENELEC	$1,325,705	$1,197,411	$1,325,705	$1,282,941	$1,325,705	$1,768,655	$1,827,610	$1,827,610	$1,768,655	$13,649,996
Pepco	$1,161,239	$1,048,861	$814,714	$1,123,780	$1,161,239	$1,265,186	$1,307,359	$1,307,359	$1,265,186	$10,454,922
PPL	$3,583,739	$3,236,926	$3,617,545	$3,468,134	$3,583,739	$3,982,417	$4,115,164	$4,115,164	$3,982,417	$33,685,245
PSEG	$2,266,920	$2,047,540	$1,777,619	$2,193,793	$2,266,920	$2,454,980	$2,536,813	$2,536,813	$2,454,980	$20,536,379
RECO	$24,425	$22,061	$18,494	$23,637	$24,425	$8,967	$9,266	$9,266	$8,967	$149,507
Total	$34,826,423	$31,456,124	$31,958,354	$33,702,990	$34,826,423	$48,036,768	$49,637,993	$49,637,993	$48,036,768	$362,119,835

Table 2-112 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007/2008 through 2013/2014 (See 2009 SOM, Table 2-107)

Delivery 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