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 2008, 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 2008.

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] PJM's market power mitigation goals have 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.

Overview

Market Structure

- **Supply.** During the June to September 2008 summer period, the PJM Energy Market received an hourly average of 154,959 MW in supply offers including hydroelectric generation.[3] The summer 2008 average supply offers were 15 MW higher than the summer 2007 average supply of 154,944 MW.

- **Demand.** The PJM system peak load in 2008 was 130,100 MW in the hour ended 1700 EPT on June 9, 2008, while the PJM peak load in 2007 was 139,428 in the hour ended 1600 on August 8, 2007.[4] The 2008 peak load was 9,328 MW, or 6.7 percent, lower than the 2007 peak load.

1 Analysis of 2008 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 *2008 State of the Market Report*, 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 August 1, 2008).

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 Volume I and Volume II of the *2008 State of the Market Report*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix M, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

- **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.** Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2008. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours were 0.2 percent in 2008, the same level as 2007. In the Real-Time Energy Market offer-capped unit hours fell from 1.1 percent in 2007 to 1.0 percent in 2008.

- **Local Market Structure.** A summary of the results of PJM's application of the three pivotal supplier test is presented for all constraints which occurred for 100 or more hours during calendar year 2008. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to ensure that owners are not subject to offer capping when the market structure is competitive and to offer cap only pivotal owners when the market structure is noncompetitive.

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 system load-weighted, average LMP was $2.04 per MWh, or 3 percent. The markup was $3.27 per MWh during peak hours and $.74 per MWh during off-peak hours. The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** On average, PJM real-time load decreased in 2008 by 2.7 percent from 2007, falling from 81,681 MW to 79,515 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. For example, overall average prices subsume congestion and price differences over time.

  PJM Real-Time Energy Market prices rose in 2008 over 2007. The system simple average LMP was 15.3 percent higher in 2008 than in 2007, $66.40 per MWh versus $57.58 per MWh. The load-weighted LMP was 15.4 percent higher in 2008 than in 2007, $71.13 per MWh versus $61.66 per MWh. The fuel-cost-adjusted, load-weighted, average LMP was 16.0 percent lower in 2008 than in 2007, $51.79 per MWh compared to $61.66 per MWh. Fuel costs in 2008 contributed to upward pressure on LMP.

- **Retroactive Change to LMP.** On September 24, 2008, PJM retroactively changed Real-Time, LMP for September 4, 2008, for hours ending 15 through 21 and the hour ending 24, and notified PJM members. The largest positive zonal impact was in the Dominion Control Zone, which experienced an average $2.43 per MWh increase as a result of the change, and the largest negative zonal impact occurred in the PECO Control Zone, which experienced an average $2.28 per MWh decrease as a result of the change. The largest positive bus-specific impact occurred at the Mt Laurel 413 KV TX1 bus, in the PSEG Control Zone, which experienced an average $29.86 per MWh increase after the changes, and the largest negative bus-specific impact occurred at the Bonsack 138 KV T1 bus, in the AEP Control Zone, which experienced an average $24.10 per MWh decrease after the changes.

- **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 single 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 2008, 14.6 percent of real-time load was supplied by bilateral contracts, 20.1 percent by spot market purchases and 65.2 percent by self-supply. Compared with 2007, reliance on bilateral contracts decreased by 2.0 percentage points; reliance on spot supply increased by 4.2 percentage points; and reliance on self-supply decreased by 2.3 percentage points in 2008.

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. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. The current approach can and has resulted in payments when the customer has taken no action to respond to market prices. 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.

Total demand-side response resources available in PJM on June 9, 2008 (the peak day in 2008), were 4,439.2 MW eligible for capacity credits and 1,898.8 MW eligible for energy payments from the Emergency Load-Response Program and 2,294.7 MW from the Economic Load-Response Program.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for calendar year 2008, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply increased by about 15 MW when comparing the summer of 2008 to the summer of 2007 while aggregate peak load decreased by 9,328 MW, modifying the general supply demand balance from 2007 with a corresponding impact on peak Energy Market prices. Overall load was also lower than in 2007. Market concentration levels remained moderate and average markup decreased. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

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

On September 24, 2008, PJM retroactively changed prices for eight hours for September 4, 2008. Changing market prices after the fact should be avoided, even when the reason is a failure to mitigate local market power, as it was here. Markets depend on prices and market participants depend on the finality and certainty of prices. Ideally, observed prices in real time would be final, but this has not yet been possible in the PJM markets. Nonetheless, PJM makes it a practice to finalize prices for the Real-Time Energy Market by noon the following day. This approach to final and certain prices is also consistent with the view that market power mitigation should be done ex ante, whenever possible, to ensure that market price signals are accurate in real time.

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

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

Energy Market results for 2008 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher fuel costs. The load-weighted, average LMP for 2008 was 15.4 percent higher than the load-weighted, average LMP for 2007. The fuel-cost-adjusted, load-weighted, average LMP in 2008 was 16.0 percent lower than the load-weighted LMP in 2007. If fuel costs for the year 2008 had been the same as for 2007, the 2008 load-weighted LMP would have been lower, $51.79 per MWh, instead of the observed $71.13 per MWh. Higher coal, gas and oil prices in 2008 resulted in higher prices in 2008 than would have occurred if fuel prices had remained at 2007 levels.

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 2008.

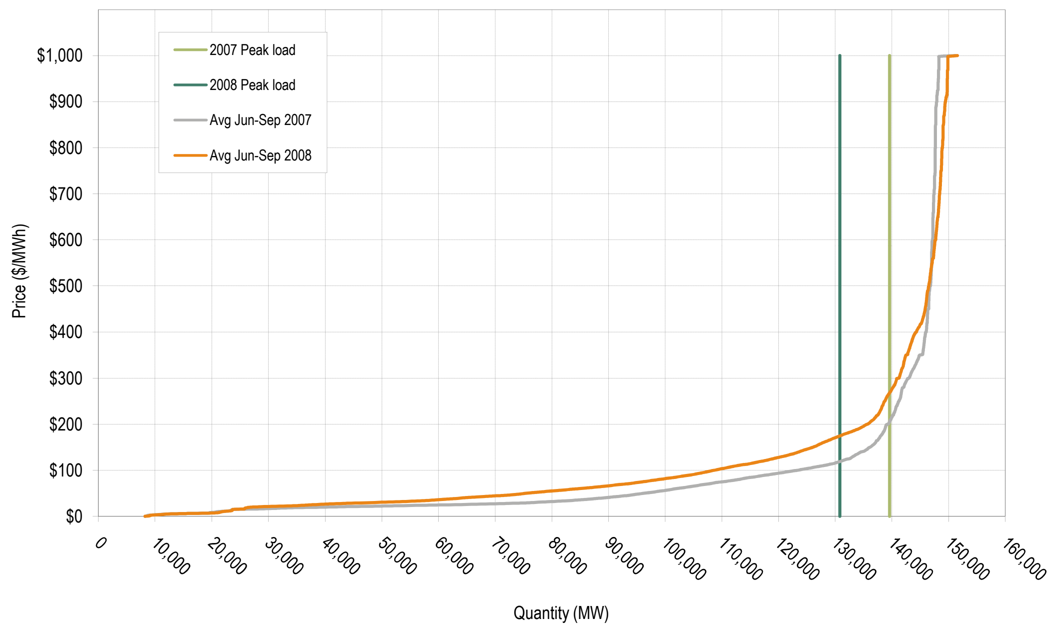
Market Structure

Supply

During the June to September 2008 summer period, the PJM Energy Market received an hourly average of 154,959 MW in total supply offers including hydroelectric generation. The summer 2008 average daily offered supply was 15 MW higher than the summer 2007 average daily offered supply of 154,944. The increase was comprised of 1,885 MWh of decreased hydroelectric power offers and 1,900 MWh of increased offers from non-hydroelectric capacity. During the summer of 2008, the peak demand was 9,328 MW, or 6.7 percent, lower than the 2007 peak, which, when combined with the upward shift of the 2008 supply curve, results in only a small difference in the price level at the supply-demand intersections. (See Figure 2-1.)

Offer prices on the 2008 supply curve are higher than on the 2007 supply curve from total supply levels of about 24,000 MW to 147,000 MW, corresponding to 2008 offers from about $15 per MWh to about $544 per MWh. During 2008, this range of offers consisted of coal-fired steam, natural gas-fired steam, combined-cycle (CC) and efficient combustion turbine (CT) units. The increase in the offer curve was primarily driven by higher fuel prices for summer 2008 compared to summer 2007. The weighted average price of coal increased by 87 percent to $4.01 per MBtu for the summer periods of 2008, the price of natural gas rose 52 percent to $10.44 per MBtu and the price of oil increased 66 percent to $23.33 per MBtu.[5]

Figure 2-1 Average PJM aggregate supply curves: Summers 2007 and 2008



During the 12 months ended May 31, 2008, 15 new units entered service in the RTO. The 15 new units included four new wind resources totaling 60.9 MW, three new diesel resources totaling 23.3 MW, two units that came out of retirement totaling 112.6 MW and six units were the result of the reclassification of external units. Total internal RTO unforced capacity increased in the 2008-2009 RPM auction by 1,762.0 MW to 156,968.0 MW from 155,206.0 MW in the 2007-2008 RPM auction. This was due to new generation (84.2 MW), units which came out of retirement (112.6 MW), capacity upgrades to existing generation and increases in demand resources, net of unit retirements (79.8 MW) and derations to existing generation and demand capacity resources. Of the 1,762.0 MW increase in total internal RTO unforced capacity, 818.5 MW were due to voluntary reductions in sell offer EFORds in the 2008-2009 auction. Of the remaining 943.5 MW, 348.2 MW (about 34 percent) were generation and 595.3 MW (about 66 percent) were DR.

Table 2-1 shows units retired during the 12 months ended May 31, 2008. Waukegan 6 retired from the ComEd zone on January 31, 2008. It was a 100 MW (79.8 UCAP, as mentioned above) sub-critical coal steam unit located in Illinois.

5 The 87 percent increase in the average price of coal consists of a 109 percent increase in the price of Central Appalachian coal, an 87 percent increase in the price of Northern Appalachian coal, a 28 percent increase in the price of Powder River Basin coal and a 73 percent increase in the price of Illinois Basin coal.

Table 2-1 Retired units: June 1, 2007, to May 31, 2008

Unit Name	Installed Capacity (MW)	Unit Type	Retire Date
ComEd Waukegan 6	100	Sub-Critical Coal	1/31/08

The net result of generation additions and subtractions, holding other factors constant, was a slight shift to the right of the aggregate supply curve. The shape of the aggregate supply curve changed only slightly as a result since the net increase in generation was less than 0.5 percent of the system supply.

Demand

Table 2-2 shows the actual coincident summer peak loads for the years 1999 through 2008.[6] The 2008 actual summer peak load of 130,100 MW was 9,328 MW less than the 2007 summer peak load of 139,428.

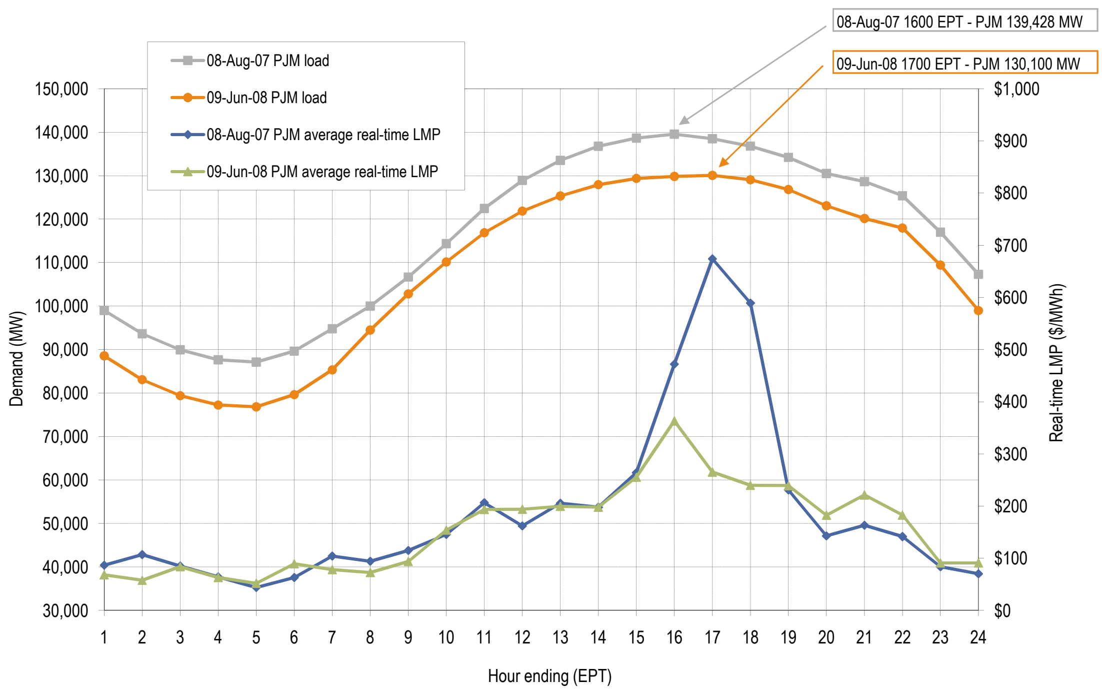
Table 2-2 Actual PJM footprint summer peak loads: 1999 to 2008

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)
1999	06-Jul-99	1400	59,365	NA
2000	26-Jun-00	1600	56,727	(2,638)
2001	09-Aug-01	1500	54,015	(2,712)
2002	14-Aug-02	1600	63,762	9,747
2003	22-Aug-03	1600	61,500	(2,262)
2004	03-Aug-04	1700	77,887	16,387
2005	26-Jul-05	1600	133,763	55,876
2006	02-Aug-06	1700	144,644	10,881
2007	08-Aug-07	1600	139,428	(5,216)
2008	09-Jun-08	1700	130,100	(9,328)

6 Peak loads shown are eMTR load. See the *2008 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of load.

The hourly load and average PJM LMP for the 2008 and 2007 summer peak days are shown in Figure 2-2.

Figure 2-2 PJM summer peak-load comparison: Monday, June 9, 2008, and Wednesday, August 8, 2007



Market Concentration

During 2008, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[7] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power and generation owners' obligations to serve load were effective in most cases in preventing the exercise of market power in these areas during 2008. If those obligations were to change or the rules were to change, however, the market power related incentives and impacts would change as a result.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their impact on price. The direct examination of offer behavior by individual market participants is one such test. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

7 For the market concentration analysis, supply curve segments are based on a classification of units that generally participate in the PJM Energy Market at varying load levels. Unit class is a primary factor for each classification; however, each unit may have different characteristics that influence the exact segment for which it is classified.

Despite their significant limitations, concentration ratios provide useful information on market structure. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner. (See Table 2-3.)

Actual net imports and import capability were incorporated in the hourly Energy Market HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant's market share increases with imports and decreases with exports.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[8]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2008 was moderately concentrated. (See Table 2-3.) Based on the hourly Energy Market measure, average HHI was 1150 with a minimum of 847 and a maximum of 1434 in 2008. The highest hourly market share was 29 percent and the highest average market share for 2008 was 21 percent.

Table 2-3 PJM hourly Energy Market HHI: Calendar year 2008

	Hourly Market HHI
Average	1150
Minimum	847
Maximum	1434
Highest market share (One hour)	29%
Highest market share (All hours)	21%
# Hours	8784
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

8 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.

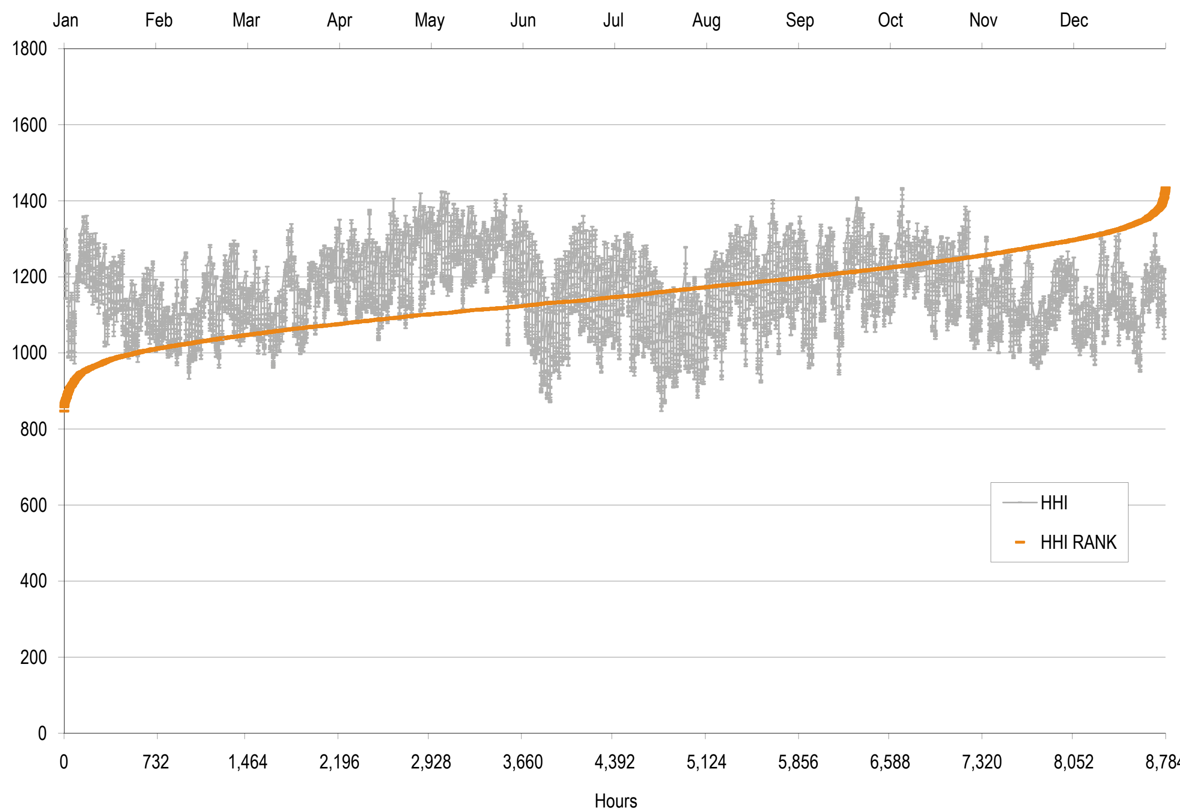
Table 2-4 includes 2008 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

Table 2-4 PJM hourly Energy Market HHI (By segment): Calendar year 2008

	Minimum	Average	Maximum
Base	1225	1549	1984
Intermediate	683	2130	6216
Peak	632	5476	10000

Figure 2-3 presents the 2008 hourly HHI values in chronological order and an HHI duration curve that shows 2008 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 6.5 percent of the hours while HHI values were in the moderately concentrated range in the remaining 93.5 percent of hours, with a maximum value of 1434, as shown in Table 2-3.

Figure 2-3 PJM hourly Energy Market HHI: Calendar year 2008



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. There are no explicit rules governing market structure or the exercise of market power in the aggregate Energy Market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

PJM has clear rules limiting the exercise of local market power.[9] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempted certain units from offer capping based on the date of their construction. Such exempt units could, and did, exercise market power, at times, that would not have been permitted if the units had not been exempt. The FERC eliminated the exemption effective May 17, 2008.[10]

Under existing rules, PJM does not apply offer capping to suppliers when structural market conditions, as measured by the three pivotal supplier test, indicate that such suppliers are reasonably likely to behave in a competitive manner. The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

PJM's three pivotal supplier test represents the practical application of the FERC market power tests in real time.[11] The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

9 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2. (January 19, 2007).
10 123 FERC ¶ 61,169 (2008).
11 See the *2008 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Levels of offer capping have historically been low in PJM, as shown in Table 2-5.

Table 2-5 Annual offer-capping statistics: Calendar years 2004 to 2008

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2004	1.3%	0.4%	0.6%	0.2%
2005	1.8%	0.4%	0.2%	0.1%
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%

Table 2-6 presents data on the frequency with which units were offer capped in 2008. Table 2-6 shows the number of generating units that met the specified criteria for total offer-capped run hours and percentage of total run hours that were offer-capped for 2008. For example, in 2008, only 1 unit was offer-capped for greater than, or equal to, 80 percent of its run hours and had 300 or more offer-capped run hours.

Table 2-6 Offer-capped unit statistics: Calendar year 2008

			2008 Offer-Capped Hours			
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	1	4
80% and < 90%	0	0	1	0	4	10
75% and < 80%	0	0	5	4	4	11
70% and < 75%	1	0	1	2	4	9
60% and < 70%	1	0	0	4	4	30
50% and < 60%	0	0	2	3	3	20
25% and < 50%	0	5	10	11	10	57
10% and < 25%	1	0	1	0	6	48

Table 2-6 shows that a small number of units are offer capped for a significant number of hours or for a significant proportion of their run hours. For example, only 53 units (about 4 percent of all units) that had offer-capped run hours of at least 200 hours (about 2 percent of all hours) in 2008 were offer capped for 10 percent or more of their run hours. Only 8 units (or about 0.7 percent of all units) that had greater than, or equal to, 400 offer-capped run hours were offer capped for 10 percent or more of their run hours.

When compared to the 2007 offer-capped statistics, 54 percent of the categories show an increase in the number of units; 17 percent of the categories show no change and 29 percent of the categories show a decrease in the number of units.[12]

12 See the *2008 State of the Market Report*, Volume II, Appendix C, "Energy Market" Table C-24 for 2007 data.

When compared to the 2006 offer-capped statistics, 48 percent of the categories show an increase in the number of units; 21 percent of the categories show no change and 31 percent of the categories show a decrease in the number of units.[13]

Units that are offer capped for greater than, or equal to, 60 percent of their run hours are designated as frequently mitigated units (FMUs). An FMU or units that are associated with the FMU (AUs) are entitled to include adders in their cost-based offers that are a form of local scarcity pricing.

Local Market Structure

In 2008, the PSEG, AP, AEP, JCPL, PENELEC, Dominion, DPL, AECO, DLCO, ComEd, PECO and Pepco Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for calendar year 2008, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[14] The Met-Ed, BGE, PPL, RECO and DAY Control Zones were not affected by constraints binding for 100 or more hours.

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint not exempt from offer capping. The FERC eliminated the exemption of interfaces effective May 17, 2008.[15] The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2008, through December 31, 2008.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when there is a small number of suppliers. The number of hours in which one or more suppliers pass the three pivotal supplier test and are not subject to offer capping increases as the number of suppliers in the local market increases. For example, the regional constraints have a larger number of suppliers and more than 62 percent of the three pivotal supplier tests have one or more passing owners. In contrast, more local constraints like the Bedington – Harmony 138 kV line in the AP Control Zone have only two suppliers and therefore are always structurally noncompetitive.

The fact that some constraints never had any generation resources that failed the three pivotal supplier test during the period analyzed does not lead to the conclusion that such constraints should never have offer capping for local market power. The same logic applies to interface constraints which were exempt from offer capping prior to May 17, 2008. Even if no generation resources associated with any of the previously exempt interface constraints failed the three pivotal suppler test during the period analyzed, that does not mean that such interfaces should always be exempt from offer capping for local market power. The fact that one or more generation resources, required to resolve these interfaces, did fail the three pivotal supplier test at times simply reinforces the point. If the generation resources associated with these interfaces always pass the three pivotal

13 See the *2008 State of the Market Report*, Volume II, Appendix C, "Energy Market" Table C-23 for 2006 data.
14 See the *2008 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.
15 123 FERC ¶ 61,169 (2008).

supplier test, there will be no offer capping; and conversely if such resources at times fail the three pivotal supplier test, appropriate offer capping will be applied.

Information is provided for each constraint including the number of tests applied and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[16] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

- **Regional 500 kV Constraints.** In 2008, several regional transmission constraints occurred for more than 100 hours. The Kammer 765/500 kV transformer, along with four interface constraints (5004/5005, AP South, Bedington – Black Oak and West) all experienced more than 100 hours of congestion.[17] The three pivotal supplier test was applied to all of these constraints. The AP South and West interfaces are two of the four interfaces for which generation owners were exempt from offer capping prior to May 17, 2008.

  Table 2-7 includes information on the three pivotal supplier test results for the three regional constraints that were never exempt from offer capping.[18] The percentage of tested intervals resulting in one or more owners passing ranged from 62 percent to 90 percent while 21 percent to 48 percent of the tests show one or more owners failing.

Table 2-7 Three pivotal supplier results summary for three regional constraints: Calendar year 2008

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	723	652	90%	149	21%
	Off Peak	535	467	87%	130	24%
Bedington - Black Oak	Peak	666	491	74%	296	44%
	Off Peak	425	301	71%	193	45%
Kammer	Peak	2,328	1,450	62%	1,111	48%
	Off Peak	4,740	3,302	70%	2,130	45%

16 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

17 The 5004/5005 Interface is comprised of two, 500 kV lines, which include the Keystone – Juniata 5004 and the Conemaugh – Juniata 5005. These two lines are located between central and western Pennsylvania.

18 The number of tests with one or more failing owners plus the number of tests with one or more passing owners can exceed the total number of tests applied. A single test can result in one or more owners passing and one or more owners failing. In such a case, the interval would be counted as including one or more passing owners and one or more failing owners.

Table 2-8 shows that, on average, during 2008 peak periods, the local markets created by the 5004/5005 Interface and the Kammer transformer had 18 owners with available supply and 13 owners with available supply, respectively. Of those owners, an average of 16 passed the test for the 5004/5005 Interface and an average of 10 passed the test for the Kammer transformer.[19] During off-peak periods, on average, the 5004/5005 Interface and the Kammer transformer had 16 owners with available supply and 14 owners with available supply. Of those owners, an average of 14 passed the test for the 5004/5005 Interface and an average of 10 passed the test for the Kammer transformer. Bedington – Black Oak, on average, had 12 owners with available supply and eight owners passed the test during on-peak periods and had 10 owners with available supply and seven owners passed the test during off-peak periods.

Table 2-8 Three pivotal supplier test details for three regional constraints: Calendar year 2008

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	80	352	18	16	2
	Off Peak	84	313	16	14	2
Bedington - Black Oak	Peak	75	174	12	8	4
	Off Peak	58	191	10	7	3
Kammer	Peak	57	207	13	10	3
	Off Peak	62	234	14	10	4

For the AP South and West interfaces, which were exempt from offer capping prior to May 17, 2008, Table 2-9 and Table 2-10 provide information on the three pivotal supplier test results from January 1, 2008 through May 16, 2008 and from May 17, 2008 through December 31, 2008. From January 1, 2008 through May 16, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 71 percent to 94 percent while 11 percent to 46 percent of the tests show one or more owners failing. From May 17, 2008 through December 31, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 61 percent to 97 percent while 7 percent to 61 percent of the tests show one or more owners failing.

Table 2-9 Three pivotal supplier results summary for the AP South and West interfaces: January 1, 2008, through May 16, 2008

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
AP South	Peak	634	464	73%	273	43%
	Off Peak	903	641	71%	414	46%
West	Peak	578	543	94%	64	11%
	Off Peak	455	420	92%	77	17%

19 The average number of owners passing and the average number of owners failing are rounded to the nearest whole number and may not sum to the average number of owners, also rounded to the nearest whole number.

Table 2-10 Three pivotal supplier results summary for the AP South and West interfaces: May 17, 2008, through December 31, 2008

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
AP South	Peak	1,575	1,088	69%	766	49%
	Off Peak	1,053	643	61%	639	61%
West	Peak	334	325	97%	22	7%
	Off Peak	186	162	87%	38	20%

Table 2-11 and Table 2-12 provide information on the three pivotal supplier test results for the AP South and West interfaces, from January 1, 2008 through May 16, 2008 and from May 17, 2008 through December 31, 2008. For AP South, on average, 12 out of 17 owners passed the test during on-peak periods and 10 out of 14 owners passed the test during off-peak periods from January 1, 2008 through May 16, 2008, and on average, 10 out of 15 owners passed the test during on-peak periods and 7 out of 12 owners passed the test during off-peak periods from May 17, 2008 through December 31, 2008. For the West Interface, on average, 16 out of 18 owners passed the test during on-peak periods, and 14 out of 16 owners passed the test during off-peak periods from January 1, 2008 through May 16, 2008, and on average, 19 out of 19 owners passed the test during on-peak periods and 16 out of 18 owners passed the test during off-peak periods from May 17, 2008 through December 31, 2008.

Table 2-11 Three pivotal supplier test details for the AP South and West interfaces: January 1, 2008, through May 16, 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	87	314	17	12	5
	Off Peak	90	332	14	10	5
West	Peak	133	648	18	16	1
	Off Peak	155	708	16	14	2

Table 2-12 Three pivotal supplier test details for the AP South and West interfaces: May 17, 2008, through December 31, 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	99	318	15	10	5
	Off Peak	98	291	12	7	5
West	Peak	122	612	19	19	1
	Off Peak	168	644	18	16	2

- **East Interface and Central Interface.** The remaining two interfaces that were exempt until May, the East and Central interface constraints occurred for fewer than 100 hours. The East Interface constraint occurred for 12 hours in 2008, while the Central Interface constraint occurred for 42 hours in 2008. Table 2-13 shows that from January 1, 2008 through May 16, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 60 percent to 100 percent while less than 40 percent of the tests showed one or more owners failing. Table 2-14 shows that from May 17, 2008 through December 31, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 79 percent to 100 percent while less than 21 percent of the tests showed one or more owners failing. No tests were applied to the East Interface from May 17, 2008 through December 31, 2008.

Table 2-13 Three pivotal supplier results summary for the East and Central interfaces: January 1, 2008, through May 16, 2008

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
Central	Peak	12	11	92%	3	25%
	Off Peak	52	50	96%	9	17%
East	Peak	9	9	100%	0	0%
	Off Peak	10	6	60%	4	40%

Table 2-14 Three pivotal supplier results summary for the East and Central interfaces: May 17, 2008, through December 31, 2008

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
Central	Peak	11	9	82%	2	18%
	Off Peak	29	29	100%	2	7%
East	Peak	0	0	NA	0	NA
	Off Peak	29	23	79%	6	21%

Table 2-15 shows that, from January 1, 2008 through May 16, 2008, on average, the local market created by the East Interface had 18 owners during peak periods and all passed the test. During off-peak periods, 9 of 13 passed the test for the East Interface. The local market created by the Central Interface had 16 owners and 15 passed the test during both on-peak and off-peak periods. Table 2-16 shows that, from May 17, 2008 through December 31, 2008, on average, the local market created by the East Interface had 17 owners during off-peak periods and 15 passed the test. No tests were applied to the East Interface during on-peak periods from May 17, 2008 through December 31, 2008. The local market created by the Central Interface had 17 owners during on-peak periods and 13 passed the test. During off-peak periods, 16 of 17 passed the test for the Central Interface.

Table 2-15 Three pivotal supplier test details for the East and Central interfaces: January 1, 2008, through May 16, 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	149	547	16	15	1
	Off Peak	108	432	16	15	1
East	Peak	170	987	18	18	0
	Off Peak	180	639	13	9	4

Table 2-16 Three pivotal supplier test details for the East and Central interfaces: May 17, 2008, through December 31, 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	133	490	17	13	3
	Off Peak	216	833	17	16	0
East	Peak	NA	NA	NA	NA	NA
	Off Peak	128	589	17	15	2

- **PSEG Control Zone Constraints.** In 2008, five constraints in the PSEG Control Zone occurred for more than 100 hours. Table 2-17 and Table 2-18 show the results of the three pivotal supplier tests applied to these constraints. For three of the five constraints, the average number of owners with available supply was four or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the Cedar Grove – Clifton 230 kV and the Cedar Grove – Roseland 230 kV lines, which had more than four owners, on average. The Cedar Grove – Clifton 230 kV and the Cedar Grove – Roseland 230 kV lines had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed the three pivotal supplier test.

Table 2-17 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Athenia - Saddlebrook	Peak	79	5	6%	77	97%
	Off Peak	427	2	0%	426	100%
Branchburg - Readington	Peak	653	56	9%	646	99%
	Off Peak	195	3	2%	193	99%
Brunswick - Edison	Peak	536	0	0%	536	100%
	Off Peak	211	0	0%	211	100%
Cedar Grove - Clifton	Peak	772	106	14%	746	97%
	Off Peak	529	107	20%	484	91%
Cedar Grove - Roseland	Peak	117	37	32%	94	80%
	Off Peak	415	80	19%	381	92%

Table 2-18 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	15	33	3	0	3
	Off Peak	18	29	3	0	3
Branchburg - Readington	Peak	19	42	4	0	4
	Off Peak	16	45	3	0	3
Brunswick - Edison	Peak	10	112	1	0	1
	Off Peak	8	87	1	0	1
Cedar Grove - Clifton	Peak	32	122	7	1	6
	Off Peak	33	118	7	1	6
Cedar Grove - Roseland	Peak	49	156	9	2	7
	Off Peak	47	145	8	1	7

- **AP Control Zone Constraints.** In 2008, there were seven constraints that occurred for more than 100 hours in the AP Control Zone. Table 2-19 and Table 2-20 show the results of the three pivotal supplier tests applied to the constraints in the AP Control Zone. For three of the seven constraints, the average number of owners with available supply was two. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the three constraints with a larger number of owners, on average. Four constraints, the Elrama – Mitchell 138 kV line, the Mount Storm – Pruntytown 500 kV line, the Sammis – Wylie Ridge 345 kV line and the Mount Storm transformer had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-19 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2008

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
Bedington	Peak	1,147	7	1%	1,145	100%
	Off Peak	443	0	0%	443	100%
Bedington - Harmony	Peak	1,523	0	0%	1,523	100%
	Off Peak	427	0	0%	427	100%
Elrama - Mitchell	Peak	364	128	35%	326	90%
	Off Peak	657	136	21%	630	96%
Meadow Brook	Peak	847	0	0%	847	100%
	Off Peak	273	2	1%	271	99%
Mount Storm	Peak	705	422	60%	405	57%
	Off Peak	928	440	47%	632	68%
Mount Storm - Pruntytown	Peak	924	620	67%	476	52%
	Off Peak	1,678	1,097	65%	891	53%
Sammis - Wylie Ridge	Peak	1,158	756	65%	624	54%
	Off Peak	4,114	2,754	67%	2,094	51%

Table 2-20 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	25	6	2	0	2
	Off Peak	25	4	2	0	2
Bedington - Harmony	Peak	11	3	2	0	2
	Off Peak	22	3	2	0	2
Elrama - Mitchell	Peak	27	65	7	2	5
	Off Peak	29	51	5	1	5
Meadow Brook	Peak	31	1	2	0	2
	Off Peak	31	1	2	0	2
Mount Storm	Peak	106	354	13	7	5
	Off Peak	93	264	10	4	6
Mount Storm - Pruntytown	Peak	98	323	11	7	4
	Off Peak	103	324	10	6	4
Sammis - Wylie Ridge	Peak	53	130	16	10	7
	Off Peak	49	122	15	9	6

- **AEP Control Zone Constraints.** In 2008, there were four constraints that occurred for more than 100 hours in the AEP Control Zone. Table 2-21 and Table 2-22 show the results of the three pivotal supplier tests applied to the constraints in the AEP Control Zone. For three of the four constraints, the average number of owners with available supply was two or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the Cloverdale – Lexington 500 kV line with the largest number of owners, on average. The Cloverdale – Lexington 500 kV line had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-21 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2008

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
Carnegie - Tidd	Peak	409	0	0%	409	100%
	Off Peak	353	0	0%	353	100%
Cloverdale - Lexington	Peak	1,044	736	70%	563	54%
	Off Peak	6,167	3,579	58%	3,996	65%
Kammer - Ormet	Peak	564	0	0%	564	100%
	Off Peak	816	0	0%	816	100%
Mahans Lane - Tidd	Peak	531	0	0%	531	100%
	Off Peak	247	0	0%	247	100%

Table 2-22 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Carnegie - Tidd	Peak	10	8	2	0	2
	Off Peak	14	9	1	0	1
Cloverdale - Lexington	Peak	77	266	15	9	6
	Off Peak	82	239	13	6	6
Kammer - Ormet	Peak	28	17	1	0	1
	Off Peak	16	15	1	0	1
Mahans Lane - Tidd	Peak	9	9	1	0	1
	Off Peak	9	10	1	0	1

- **JCPL Control Zone Constraints.** In 2008, the Atlantic – Larrabee 230 kV line was the only constraint in the JCPL Control Zone to occur for more than 100 hours. Table 2-23 and Table 2-24 show the results of the three pivotal supplier tests applied to this constraint. The average number of owners with available supply was four on peak and three off peak. The three pivotal supplier test results reflect this, as 97 percent of the tests applied on peak and 100 percent of the tests applied off peak resulted in one or more owners failing the test.

Table 2-23 Three pivotal supplier results summary for constraints located in the JCPL Control Zone: Calendar year 2008

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
Atlantic - Larrabee	Peak	679	212	31%	656	97%
	Off Peak	632	9	1%	630	100%

Table 2-24 Three pivotal supplier test details for constraints located in the JCPL Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Atlantic - Larrabee	Peak	23	42	4	1	4
	Off Peak	25	27	3	0	3

- **PENELEC Control Zone Constraints.** In 2008, there were three constraints in the PENELEC Control Zone that occurred for more than 100 hours in the PENELEC Control Zone. Table 2-25 and Table 2-26 show the results of the three pivotal supplier tests applied to the constraints in the PENELEC Control Zone. The average number of owners with available supply was three on peak and three off peak for the East Towanda transformer and the Homer City – Shelocta 230 kV line, and one on peak and one off peak for the Garman – Westover 115 kV line. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-25 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: Calendar year 2008

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
East Towanda	Peak	1,361	35	3%	1,353	99%
	Off Peak	452	1	0%	452	100%
Garman - Westover	Peak	628	0	0%	628	100%
	Off Peak	779	0	0%	779	100%
Homer City - Shelocta	Peak	319	4	1%	316	99%
	Off Peak	327	4	1%	326	100%

Table 2-26 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
East Towanda	Peak	19	5	3	0	2
	Off Peak	8	4	3	0	3
Garman - Westover	Peak	10	5	1	0	1
	Off Peak	6	6	1	0	1
Homer City - Shelocta	Peak	23	73	3	0	3
	Off Peak	24	57	3	0	3

- **Dominion Control Zone Constraints.** In 2008, there were four constraints in the Dominion Control Zone that occurred for more than 100 hours. Table 2-27 and Table 2-28 show the results of the three pivotal supplier test applied to the constraints in the Dominion Control Zone. The average number of owners with available supply was one on peak and one off peak for the Beechwood – Kerr Dam and the Halifax – Mount Laurel 115 kV lines. The average number of owners with available supply was four on peak and five or less off peak for the Clover transformer and the Danville – East Danville 138 kV line. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-27 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2008

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	457	0	0%	457	100%
	Off Peak	70	0	0%	70	100%
Clover	Peak	321	144	45%	321	100%
	Off Peak	2	0	0%	2	100%
Danville - East Danville	Peak	87	9	10%	85	98%
	Off Peak	415	5	1%	415	100%
Halifax - Mount Laurel	Peak	444	31	7%	413	93%
	Off Peak	455	30	7%	425	93%

Table 2-28 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2008

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	5	3	1	0	1
	Off Peak	6	4	1	0	1
Clover	Peak	38	106	4	1	3
	Off Peak	10	104	5	0	5
Danville - East Danville	Peak	38	31	4	0	3
	Off Peak	30	27	2	0	2
Halifax - Mount Laurel	Peak	9	3	1	0	1
	Off Peak	13	3	1	0	1

- **DPL Control Zone Constraints.** In 2008, the Keeney At5n transformer and the North Seaford – Pine Street 69 kV line were the two constraints in the DPL Control Zone to occur for more than 100 hours. Table 2-29 and Table 2-30 show the results of the three pivotal supplier test applied to the two constraints. The average number of owners with available supply was five on peak and four off peak for the Keeney At5n transformer and two on peak and two off peak for the North Seaford – Pine Street 69 kV line. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-29 Three pivotal supplier results summary for constraints located in the DPL Control Zone: Calendar year 2008

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
Keeney At5n	Peak	304	64	21%	284	93%
	Off Peak	196	24	12%	191	97%
North Seaford - Pine Street	Peak	255	0	0%	255	100%
	Off Peak	145	0	0%	145	100%

Table 2-30 Three pivotal supplier test details for constraints located in the DPL Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Keeney At5n	Peak	28	121	5	1	4
	Off Peak	31	126	4	0	4
North Seaford - Pine Street	Peak	3	20	2	0	2
	Off Peak	3	18	2	0	2

- **AECO Control Zone Constraints.** In 2008, there were three constraints in the AECO Control Zone that occurred for more than 100 hours. Table 2-31 and Table 2-32 show the results of the three pivotal supplier test applied to the constraints in the AECO Control Zone. The average number of owners with available supply was one. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-31 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2008

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
Churchtown	Peak	170	0	0%	170	100%
	Off Peak	53	0	0%	53	100%
Monroe	Peak	1,132	0	0%	1,132	100%
	Off Peak	284	0	0%	284	100%
Quinton - Roadstown	Peak	80	0	0%	80	100%
	Off Peak	35	0	0%	35	100%

Table 2-32 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Churchtown	Peak	11	10	1	0	1
	Off Peak	15	10	1	0	1
Monroe	Peak	17	6	1	0	1
	Off Peak	14	4	1	0	1
Quinton - Roadstown	Peak	2	4	1	0	1
	Off Peak	2	6	1	0	1

- **DLCO Control Zone Constraints.** In 2008, three constraints in the DLCO Control Zone experienced more than 100 hours of congestion. Table 2-33 and Table 2-34 show the results of the three pivotal supplier test applied to the constraints in the DLCO Control Zone. The average number of owners with available supply was one on peak and one off peak for the Cheswick – Logans Ferry and the Cheswick – Universal 138 kV lines and two on peak and two off peak for the Cheswick – Evergreen 138 kV line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-33 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2008

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
Cheswick - Evergreen	Peak	170	0	0%	170	100%
	Off Peak	26	0	0%	26	100%
Cheswick - Logans Ferry	Peak	283	0	0%	283	100%
	Off Peak	157	0	0%	157	100%
Cheswick - Universal	Peak	163	0	0%	163	100%
	Off Peak	34	0	0%	34	100%

Table 2-34 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cheswick - Evergreen	Peak	12	47	2	0	2
	Off Peak	13	36	2	0	2
Cheswick - Logans Ferry	Peak	8	25	1	0	1
	Off Peak	8	30	1	0	1
Cheswick - Universal	Peak	16	92	1	0	1
	Off Peak	19	94	1	0	1

- **ComEd Control Zone Constraints.** In 2008, there were three constraints that occurred for more than 100 hours in the ComEd Control Zone. Table 2-35 and Table 2-36 show the results of the three pivotal supplier tests applied to the constraints in the ComEd Control Zone. The average number of owners with available supply was one for the Cherry Valley transformer and three for the Crete – East Frankfort 345 kV line. The average number of owners with available supply was three on peak and ten off peak for the Burnham – Munster 345 kV line. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only during off-peak periods for the Burnham – Munster 345 kV line with the largest number of owners and more effective supply, on average.

Table 2-35 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Burnham - Munster	Peak	378	13	3%	366	97%
	Off Peak	633	223	35%	451	71%
Cherry Valley	Peak	117	0	0%	117	100%
	Off Peak	15	0	0%	15	100%
Crete - East Frankfort	Peak	18	0	0%	18	100%
	Off Peak	2,262	59	3%	2,238	99%

Table 2-36 Three pivotal supplier test details for constraints located in the ComEd Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Munster	Peak	304	54	3	1	3
	Off Peak	220	120	10	6	5
Cherry Valley	Peak	10	15	1	0	1
	Off Peak	21	9	1	0	1
Crete - East Frankfort	Peak	54	62	3	0	3
	Off Peak	49	37	3	0	3

- **PECO Control Zone Constraints.** In 2008, the Graceton – Peach Bottom 230 kV line was the only constraint in the PECO Control Zone to occur for more than 100 hours. Table 2-37 and Table 2-38 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was ten on peak and ten off peak. The three pivotal supplier test results reflect this, as 61 percent of the tests showed one or more owners failing.

Table 2-37 Three pivotal supplier results summary for constraints located in the PECO Control Zone: Calendar year 2008

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
Graceton - Peach Bottom	Peak	138	93	67%	84	61%
	Off Peak	492	269	55%	300	61%

Table 2-38 Three pivotal supplier test details for constraints located in the PECO Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Graceton - Peach Bottom	Peak	26	73	10	6	5
	Off Peak	25	59	10	5	5

- **Pepco Control Zone Constraints.** In 2008, the Dickerson – Plesant View 230 kV line was the only constraint in the Pepco Control Zone to occur for more than 100 hours. Table 2-39 and Table 2-40 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was 16 on peak and 14 off peak. The three pivotal supplier test results reflect this, as 39 percent of the tests during on-peak periods and 40 percent of the tests during off-peak periods showed one or more owners failing.

Table 2-39 Three pivotal supplier results summary for constraints located in the Pepco Control Zone: Calendar year 2008

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
Dickerson - Plesant View	Peak	592	472	80%	232	39%
	Off Peak	215	171	80%	86	40%

Table 2-40 Three pivotal supplier test details for constraints located in the Pepco Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Dickerson - Plesant View	Peak	61	240	16	13	4
	Off Peak	57	213	14	10	4

Market Performance: Markup

The markup index is a summary measure of the behavior or conduct of individual marginal units. However the markup conduct measure does not explicitly capture the impact of this behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[20]

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculates an explicit measure of the impact of marginal unit markups on LMP. 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.

Markup by System Price Levels

The price component measure uses load-weighted, price-based LMP and load-weighted LMP computed using cost-based offers for all marginal units. The markup component of price is computed by calculating the system price, based on the cost-based offers of the marginal units and comparing that to the actual system price to determine how much of the LMP can be attributed to markup.

20 This is the same method used to calculate the fuel-cost-adjusted LMP and the components of LMP.

Table 2-41 shows the average markup component of observed price when the PJM system LMP was in the identified price range.

Table 2-41 Average markup component (By price category): Calendar year 2008

	Average Markup Component	Frequency
Below $20	($4.66)	2.5%
$20 to $39.99	($4.60)	22.0%
$40 to $59.99	($1.11)	31.2%
$60 to $79.99	$2.43	17.7%
$80 to $99.99	$5.09	10.1%
$100 to $119.99	$7.31	7.0%
$120 to $139.99	$10.89	3.9%
$140 to $159.99	$12.64	2.4%
Above $160	$20.73	3.1%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

On January 25, 2005, the FERC ordered that frequently offer-capped units be provided additional compensation as a form of scarcity pricing, consistent with a recommendation of the MMU.[21] A frequently mitigated unit (FMU) was defined to be a unit that was offer capped for 80 percent or more of its run hours during the prior calendar year. FMUs were allowed either a $40 adder to their cost-based offers in place of the 10 percent adder, or the unit-specific, going-forward costs of the affected unit as a cost-based offer.

In the second half of 2005, discussions were held regarding scarcity pricing and local market power mitigation that led to a settlement agreement accepted by the FERC on January 27, 2006.[22] The settlement agreement revised the definition of FMUs to provide for a set of graduated adders associated with increasing levels of offer capping.[23] Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[24] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.

The settlement agreement further amended the OA to designate associated units (AUs), also at the recommendation of the MMU. An AU is a unit that is electrically and economically identical to an FMU, but does not qualify for the same adder. The settlement agreement provides for monthly

21 110 FERC ¶ 61,053 (2005).
22 114 FERC ¶ 61, 076 (2006).
23 *PJM Interconnection, L.L.C.*, Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
24 OA, Fifth Revised Sheet No. 131B (Effective July 3, 2007).

designation of FMUs and AUs, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[25]

For example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site, to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

As another example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 72 percent of its run hours, that unit would be eligible for a Tier 2 FMU adder. However, the second unit is an AU to the first unit and would, therefore, be eligible for the higher Tier 3 adder.

Table 2-42 shows the number of FMUs and AUs in each month of 2008. For example, in December 2008, there were 28 FMUs and AUs in Tier 1, 51 FMUs and AUs in Tier 2, and 61 FMUs and AUs in Tier 3.

Table 2-42 Frequently mitigated units and associated units (By month): Calendar year 2008

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	19	15	69	103
February	30	12	81	123
March	27	21	75	123
April	26	26	72	124
May	23	25	76	124
June	27	26	75	128
July	27	28	73	128
August	28	37	63	129
September	18	45	53	116
October	31	35	61	127
November	36	30	64	130
December	28	51	61	140

Table 2-43 shows the number of months FMUs and AUS were eligible for any adder (Tier 1, Tier 2 or Tier 3) during 2008. Of the 171 units eligible in at least one month during 2008, 114 units (67 percent) were FMUs or AUs for more than eight months. Approximately half of the units (74 units or 43 percent) were eligible every month during the year. This demonstrates that the group of FMUs and AUs is fairly stable, although units may move between the tier levels, month-to-month.

25 OA, Fifth Revised Sheet No. 132 (Effective July 3, 2007). In 2007, the FERC approved OA revisions to clarify the AU criteria.

Table 2-43 Frequently mitigated units and associated units total months eligible: Calendar year 2008

Months Adder-Eligible	FMU & AU Count
1	16
2	15
3	8
4	3
5	3
6	3
7	4
8	5
9	2
10	13
11	25
12	74
Total	171

FMU and AU adders contributed $.30 per MWh to system average LMP in 2008, out of a real-time, load weighted LMP of $71.13 per MWh.

Market Performance: Load and LMP

The PJM system load and LMP reflect the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market, which started on January 1, 1998, and the Day-Ahead Energy Market, which started on June 1, 2000.

Load

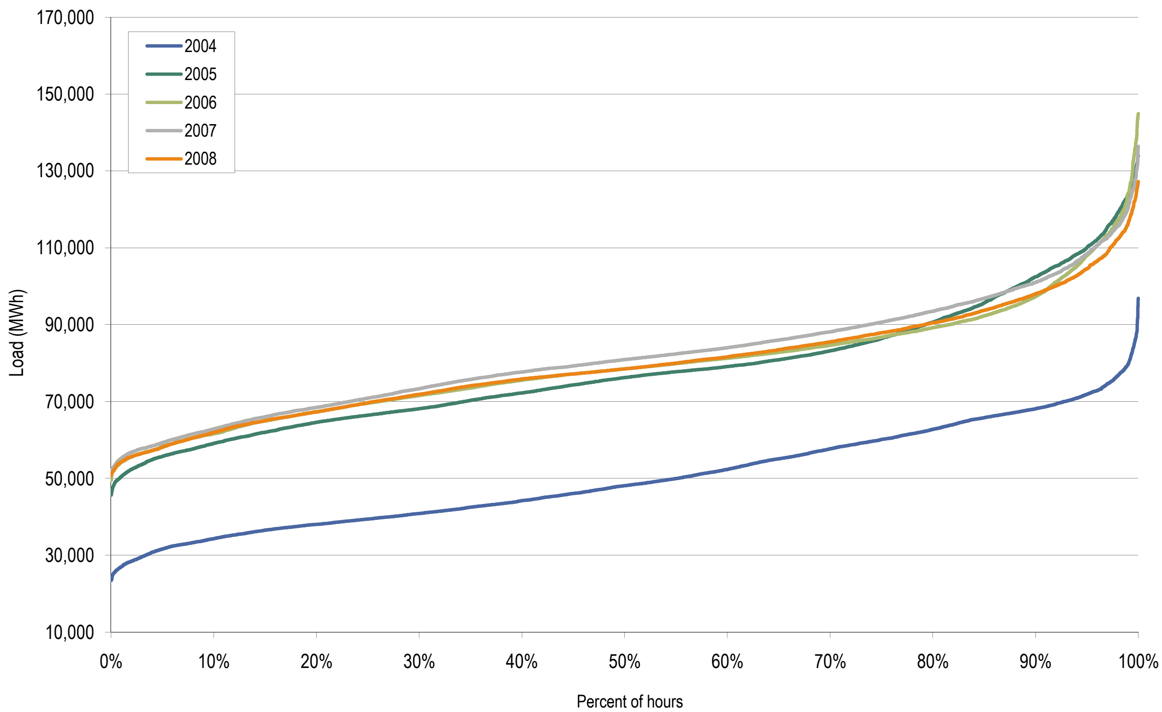
Real-Time Load

PJM real-time load is the total hourly accounting load in real time.[26]

PJM Real-Time Load Duration

Figure 2-4 shows PJM real-time load duration curves from 2004 to 2008. A load duration curve shows the percent of hours that load was at, or below, a given level for the year.

Figure 2-4 PJM real-time load duration curves: Calendar years 2004 to 2008



26 All real-time load data in Section 2, "Energy Market, Part 1," "Market Performance: Load and LMP" are based on PJM accounting load. See the *2008 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of accounting load.

PJM Real-Time, Annual Average Load

Table 2-44 presents summary real-time load statistics for the 11-year period 1998 to 2008. The average load of 79,515 MWh in 2008 was 2.7 percent lower than the 2007 annual average hourly load. This average load was based on the PJM hourly accounting load. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load because of the implementation of marginal loss pricing. The average 2007 load of 81,681 MWh includes losses prior to June 1 but does not include losses after June 1, 2007. If transmission losses had been included, the real-time, annual average load for 2007 would have been 82,857 MWh, which was 4.3 percent higher than the 2006 real-time, annual average hourly load.[27] The average 2008 load of 79,515 does not include losses. If transmission losses had been included, the real-time, annual average load for 2008 would have been 81,442 MWh, which was 2.4 percent higher than the 2008 real-time, annual average hourly load.[28]

Table 2-44 PJM real-time average load: Calendar years 1998 to 2008

	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%	36.4%
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%)

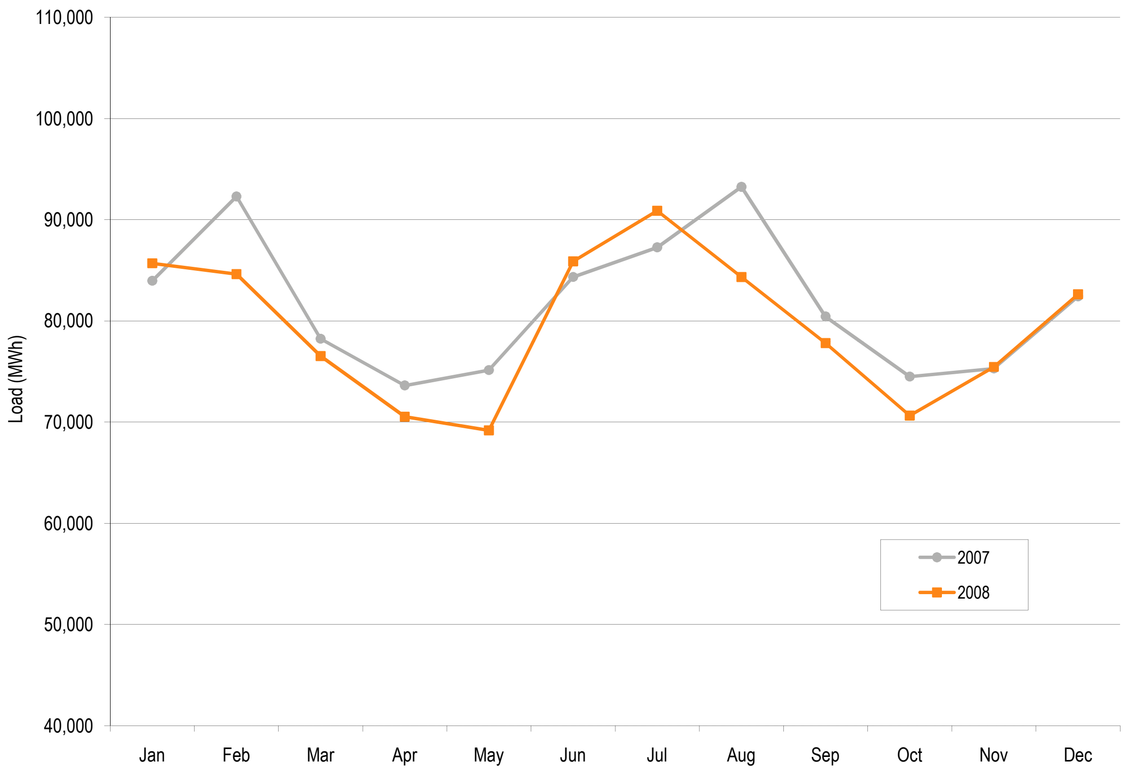
27 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.

28 Data quality improvements have caused values in some tables in this section to vary slightly from previously published results.

PJM Real-Time, Monthly Average Load

Figure 2-5 compares the real-time, monthly average hourly loads of 2008 with those of 2007.

Figure 2-5 PJM real-time average load: Calendar years 2007 to 2008



PJM real-time load is significantly affected by temperature. PJM uses the Temperature-Humidity Index (THI) as the weather variable in the PJM load forecast model for the cooling season (June, July and August).[29] THI is a measure of effective temperature using temperature and relative humidity. Table 2-45 shows the monthly minimum, average and maximum of the PJM hourly THI for the cooling months in 2007 and 2008. When comparing 2008 to 2007, changes in THI were mixed, consistent with the changes in load. For the cooling months of 2008, the average THI was 70.71, 0.3 percent lower than the average 71.90 THI for 2007. However, the maximum THI (81.30) and minimum THI (54.94) in 2008 were 1.9 percent lower and 0.9 percent lower, respectively, than the maximum THI (82.84) and minimum THI (55.46) in 2007 during the cooling months.

29 Temperature and relative humidity data that were used to calculate THI were obtained from Meteorlogix. PJM hourly THI is the weighted-average zonal hourly THI weighted by average, annual peak zonal share (Coincident Factor) from 1998 to the year for which the calculation is made. For additional information on THI calculations, see PJM. "Manual 19: Load Forecasting and Analysis" (December 1, 2008), Section 4, pp. 20-21.

Table 2-45 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2007 and 2008

	2007			2008			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	55.46	69.18	80.94	54.94	70.16	81.30	(0.9%)	1.4%	0.4%
Jul	55.78	70.92	80.29	62.00	72.25	80.34	11.2%	1.9%	0.1%
Aug	61.60	72.53	82.84	59.89	69.70	78.62	(2.8%)	(3.9%)	(5.1%)

Day-Ahead Load

In the PJM Day-Ahead Energy Market, three types of financially binding demand bids are made and cleared:

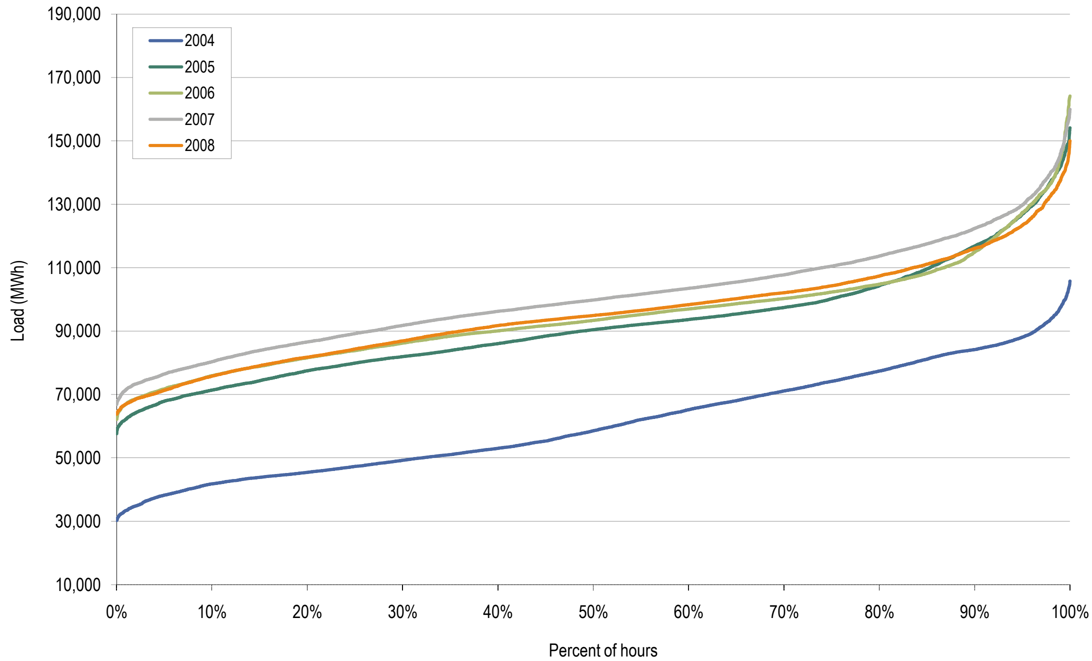
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A decrement bid is a financial bid that can be submitted by any market participant.

PJM day-ahead load is the hourly total of the above three types of cleared demand bids.

PJM Day-Ahead Load Duration

Figure 2-6 shows PJM day-ahead load duration curves from 2004 to 2008.

Figure 2-6 PJM day-ahead load duration curves: Calendar years 2004 to 2008



PJM Day-Ahead, Annual Average Load

Table 2-46 presents summary day-ahead load statistics for the five-year period 2004 to 2008. The average load of 95,522 MWh in 2008 was 5.3 percent lower than the 2007 annual average load. The cleared decrement bids, fixed demand and price-sensitive demand in 2008 were 13.3 percent, 3.2 percent and 1.2 percent lower than the corresponding loads in 2007, respectively.

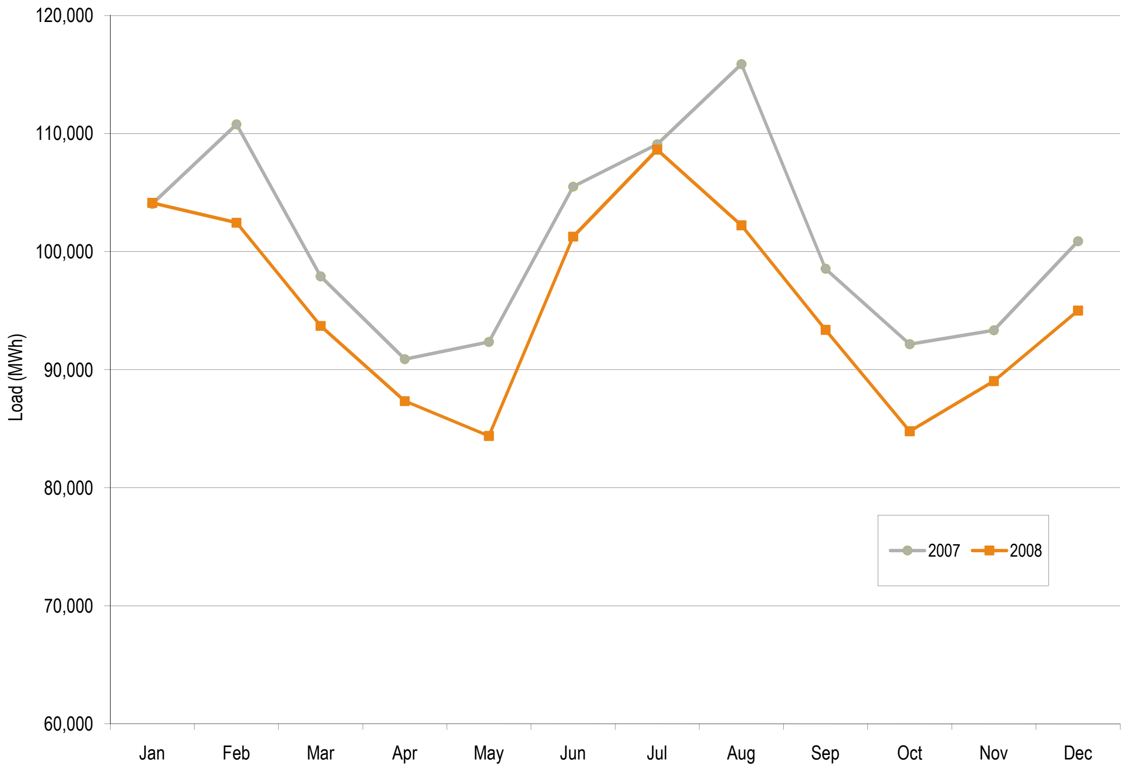
Table 2-46 PJM day-ahead average load: Calendar years 2004 to 2008

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2004	61,034	58,544	16,318	NA	NA	NA
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%)

PJM Day-Ahead, Monthly Average Load

Figure 2-7 compares the day-ahead, monthly average loads of 2008 with those of 2007.

Figure 2-7 PJM day-ahead average load: Calendar years 2007 to 2008



Real-Time and Day-Ahead Load

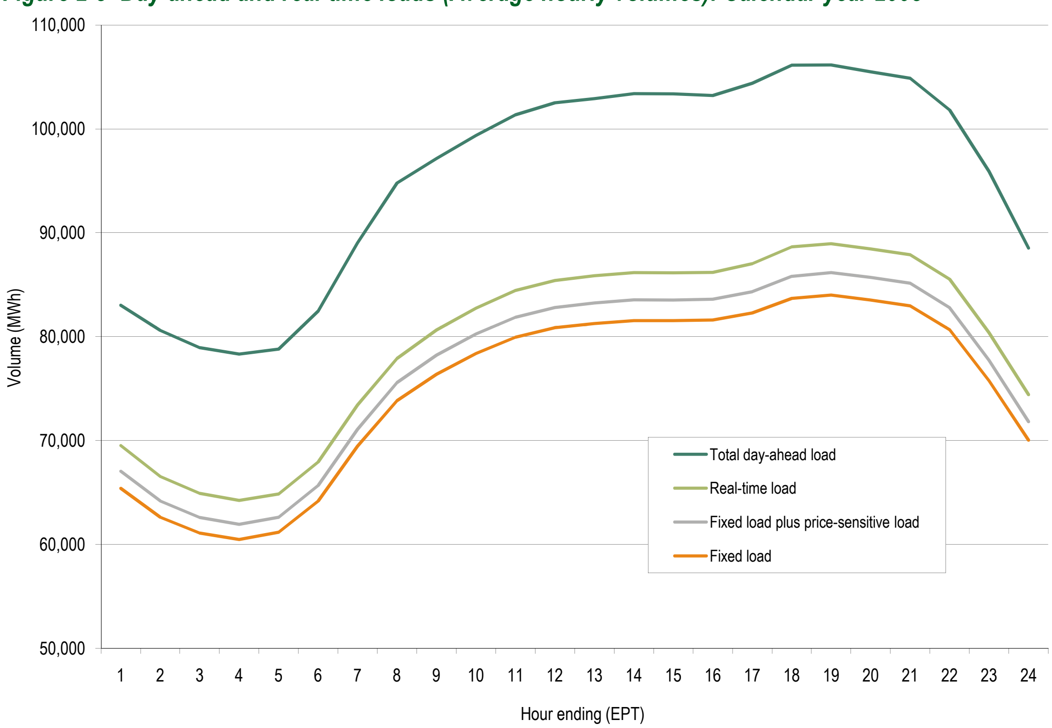
Table 2-47 presents summary statistics for the 2008 day-ahead and real-time loads and the average difference between them. The sum of day-ahead cleared fixed demand and price-sensitive demand averaged 2554 MWh less than real-time average load. Total day-ahead load (the sum of the three types of cleared demand bids) averaged 16,007 MWh more than real-time load. Table 2-47 shows that, at 78.6 percent, fixed demand was the largest component of day-ahead load. At 1.9 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 19.4 percent of day-ahead load.

Table 2-47 Cleared day-ahead and real-time load (MWh): Calendar year 2008

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus DEC Bid
Average	75,115	1,846	18,561	95,522	79,515	16,007	(2,554)
Median	74,625	1,835	18,306	94,886	78,481	16,405	(1,901)
Standard deviation	12,757	388	2,960	15,439	13,758	1,681	(1,279)

Figure 2-8 shows the average 2008 hourly cleared volumes of fixed-demand bids, the sum of cleared fixed-demand and price-sensitive bids, total day-ahead load and real-time load. During 2008, real-time, hourly average load was higher than cleared fixed-demand load plus cleared price-sensitive load in the Day-Ahead Energy Market, although the reverse was true for 5.1 percent of the hours. When cleared decrement bids are included, day-ahead load always exceeded real-time load.

Figure 2-8 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2008



Real-Time and Day-Ahead Generation

Real-time generation is the actual production of electricity during the operating day.

In the Day-Ahead Energy Market,[30] three types of financially binding generation offers are made and cleared:

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, or as a minimum amount of MWh that must run on a specific unit that also has a dispatchable component above the minimum.[31]

- **Generator Offer.** Offer to supply a schedule of MWh from a specific unit and the corresponding offer prices.

- **Increment Offer (INC).** Financial offer to supply specified MWh at, or above, a given price. An increment offer is a financial offer that can be submitted by any market participant.

Table 2-48 presents summary statistics for 2008 day-ahead and real-time generation and the average differences between them. Day-ahead cleared generation from physical units averaged 724 MWh higher than real-time generation. Day-ahead cleared generation plus cleared INC offers averaged 15,626 MWh more than real-time generation. Table 2-48 also shows that cleared generation and INC offers accounted for 85.0 percent and 15.0 percent of day-ahead supply, respectively.

Table 2-48 Day-ahead and real-time generation (MWh): Calendar year 2008

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	84,202	14,902	99,104	83,478	724	15,626
Median	83,466	14,555	98,210	82,223	1,243	15,987
Standard deviation	14,268	2,252	15,558	13,787	481	1,771

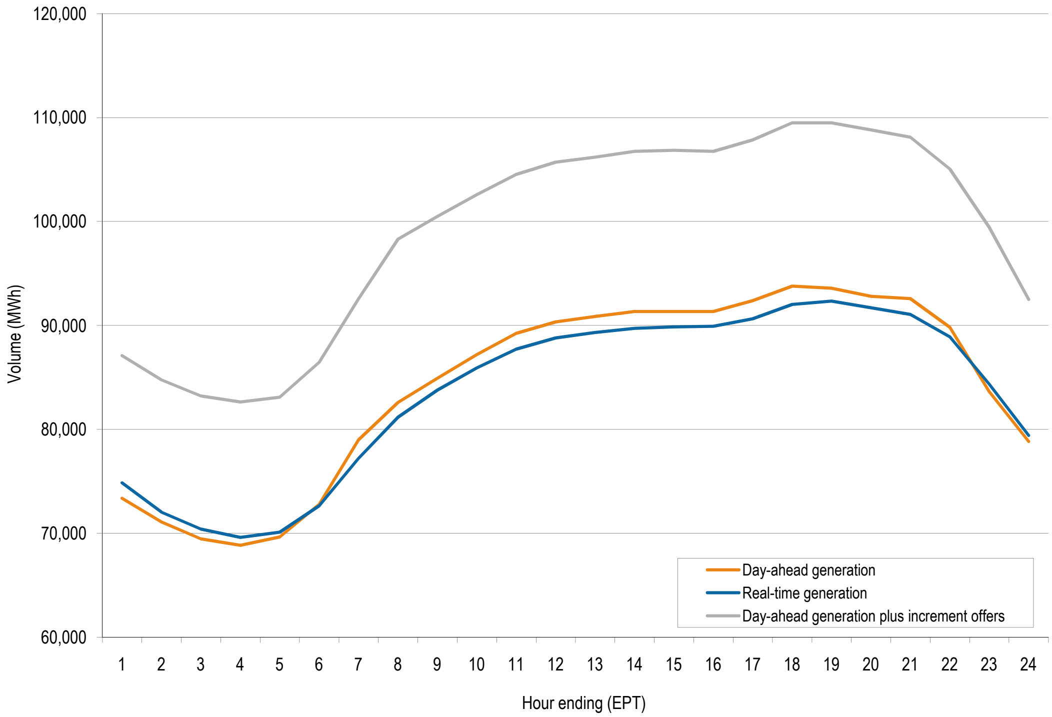
Figure 2-9 shows average hourly cleared volumes of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2008.[32] Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. During 2008, real-time, hourly average generation was lower than day-ahead generation from physical units, although the reverse was true for 37.8 percent of the hours. When cleared increment offers are included, average hourly total day-ahead cleared MW offers exceeded real-time generation.

30 All references to day-ahead generation and increment offers are presented in cleared MWh in the "Real-Time and Day-Ahead Generation" portion of the *2008 State of the Market Report,* Volume II, Section 2, "Energy Market, Part 1."

31 The definition of self-scheduled is based on documentation from PJM. "eMKT User Guide" (June 2007), pp. 49-51.

32 Generation data are the sum of MWh at every generation bus in PJM with positive output.

Figure 2-9 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2008



Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[33]

Real-Time LMP

Real-time LMP is the hourly LMP for the PJM Real-Time Energy Market.

Real-Time Average LMP

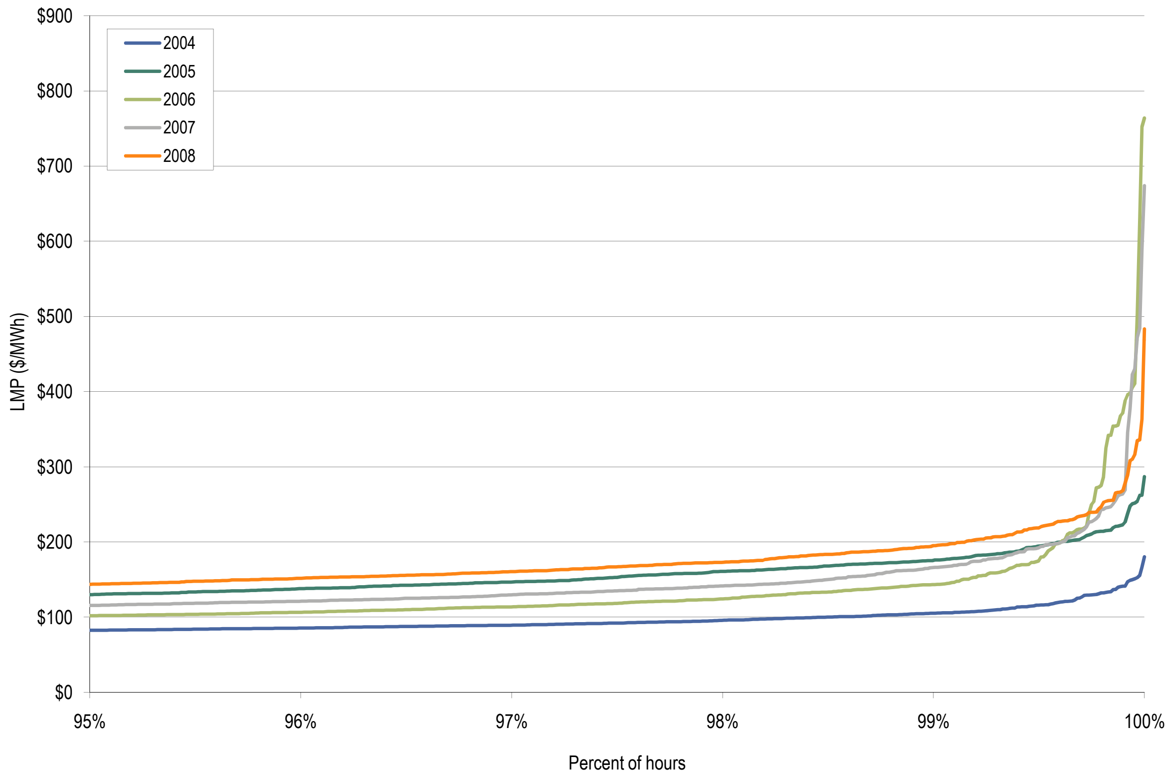
PJM Real-Time LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-10 presents price duration curves for hours above the 95th percentile from 2004 to 2008. As Figure 2-10 shows, LMPs were less than $100 per MWh during 95 percent or more of the hours for the year 2004 and less than $150 during 95 percent or more of the hours for the years 2005 to 2008.[34]

33 See the *2008 State of the Market Report*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and comparisons and Appendix H, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

34 See the *2008 State of the Market Report*, Volume II, Appendix C, "Energy Market."

Figure 2-10 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2004 to 2008



PJM Real-Time, Annual Average LMP

Table 2-49 shows the PJM real-time, annual, simple average LMP for the 11-year period 1998 to 2008.[35] The system simple average LMP for 2008 was 15.3 percent higher than the 2007 annual average, $66.40 per MWh versus $57.58 per MWh.

35 The system annual, simple average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Table 2-49 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 to 2008

	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	35.3%	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%

Zonal Real-Time, Annual Average LMP

Table 2-50 shows PJM zonal real-time, simple average LMP for 2007 and 2008. The largest zonal increase was in the AECO Control Zone which experienced a $15.68, or 24.1 percent, increase over 2007 and the smallest increase was in the ComEd Control Zone which experienced a $3.67 increase, or 8.0 percent, over 2007.

Table 2-50 Zonal real-time, simple average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AECO	$65.02	$80.70	$15.68	24.1%
AEP	$46.55	$53.42	$6.87	14.7%
AP	$57.45	$65.85	$8.40	14.6%
BGE	$69.79	$80.05	$10.25	14.7%
ComEd	$45.71	$49.38	$3.67	8.0%
DAY	$46.47	$53.68	$7.21	15.5%
DLCO	$43.93	$48.81	$4.88	11.1%
Dominion	$66.75	$75.87	$9.12	13.7%
DPL	$64.15	$77.20	$13.05	20.3%
JCPL	$65.74	$78.80	$13.06	19.9%
Met-Ed	$64.57	$74.70	$10.13	15.7%
PECO	$62.60	$75.07	$12.47	19.9%
PENELEC	$54.80	$63.37	$8.57	15.6%
Pepco	$70.33	$80.45	$10.12	14.4%
PPL	$62.02	$73.35	$11.33	18.3%
PSEG	$65.92	$79.14	$13.22	20.1%
RECO	$64.85	$77.46	$12.61	19.5%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-51 shows the real-time, simple average LMP for all or part of the jurisdictions within the PJM footprint during 2007 and 2008. The largest increase was in New Jersey which experienced a $13.50, or 20.5 percent, increase over 2007, and the smallest increase was in Illinois which experienced a $3.67, or 8.0 percent, increase over 2007.

Table 2-51 Jurisdiction real-time, simple average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
Delaware	$63.44	$76.26	$12.82	20.2%
Illinois	$45.71	$49.38	$3.67	8.0%
Indiana	$46.25	$53.01	$6.76	14.6%
Kentucky	$46.55	$53.80	$7.25	15.6%
Maryland	$69.63	$79.75	$10.12	14.5%
Michigan	$46.82	$54.07	$7.25	15.5%
New Jersey	$65.77	$79.27	$13.50	20.5%
North Carolina	$62.62	$71.69	$9.07	14.5%
Ohio	$45.69	$52.64	$6.95	15.2%
Pennsylvania	$58.76	$68.98	$10.22	17.4%
Tennessee	$47.32	$54.36	$7.04	14.9%
Virginia	$63.91	$73.20	$9.29	14.5%
West Virginia	$48.50	$55.02	$6.52	13.4%
District of Columbia	$70.25	$80.57	$10.32	14.7%

Hub Real-Time, Annual Average LMP

Table 2-52 shows the real-time, simple average LMPs at the PJM hubs for 2007 and 2008. Hub prices are average LMPs across a defined set of buses, created to provide market participants with trading points that exhibit greater price stability than individual buses. The largest price increase was for the New Jersey Hub which experienced an $13.40, or 20.4 percent, increase over 2007, and the smallest increase was for the Chicago Gen Hub which experienced a $3.49, or 7.7 percent, increase over 2007.

Table 2-52 Hub real-time, simple average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AEP Gen Hub	$44.14	$50.35	$6.21	14.1%
AEP-DAY Hub	$46.25	$53.05	$6.80	14.7%
Chicago Gen Hub	$45.11	$48.60	$3.49	7.7%
Chicago Hub	$45.76	$49.43	$3.67	8.0%
Dominion Hub	$64.65	$73.89	$9.24	14.3%
Eastern Hub	$63.92	$77.15	$13.23	20.7%
N Illinois Hub	$45.47	$48.99	$3.52	7.7%
New Jersey Hub	$65.62	$79.02	$13.40	20.4%
Ohio Hub	$46.18	$53.09	$6.91	15.0%
West Interface Hub	$51.67	$58.40	$6.73	13.0%
Western Hub	$59.77	$68.53	$8.76	14.7%

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than simple average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMPs, each weighted by the PJM total hourly load.

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

Table 2-53 shows the PJM real-time, annual, load-weighted, average LMP for the 11-year period 1998 to 2008. The load-weighted, average system LMP for 2008 was 15.4 percent higher than the 2007 annual, load-weighted, average, $71.13 per MWh versus $61.66 per MWh.

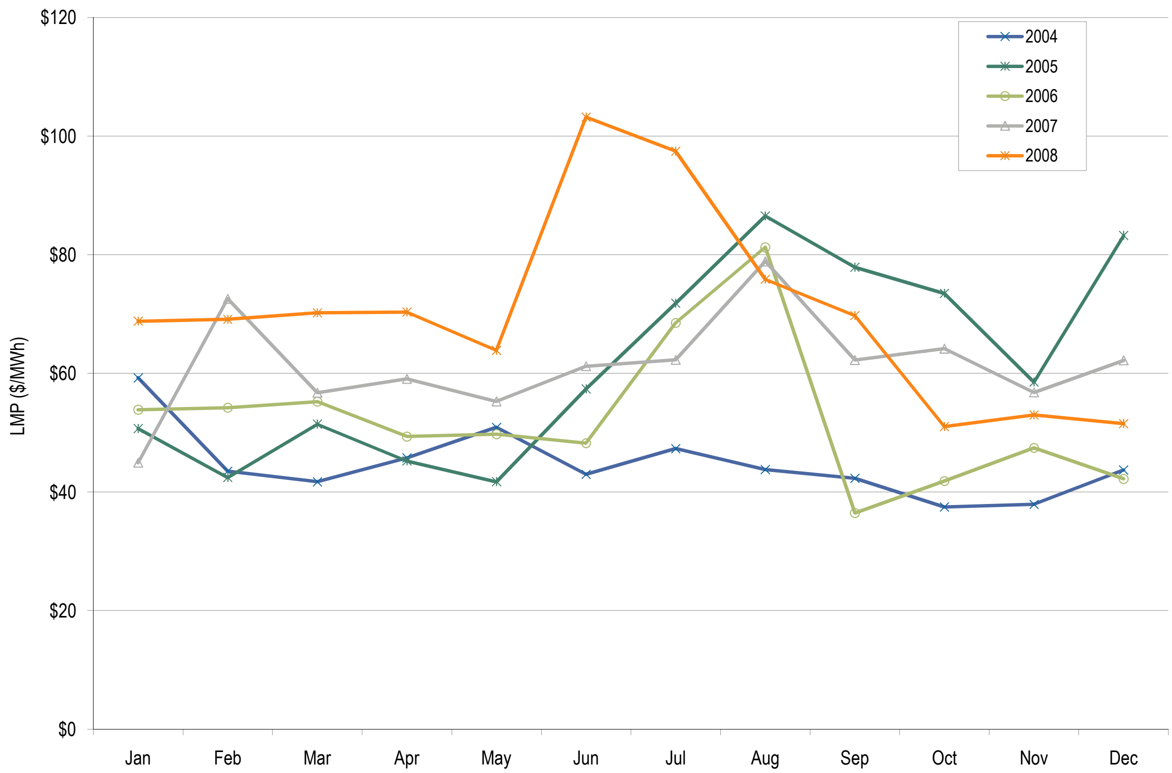
Table 2-53 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2008

	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%	132.9%
2000	$30.72	$20.51	$28.38	(9.8%)	7.8%	(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%)	(0.8%)
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%

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

Figure 2-11 shows the PJM real-time, monthly, load-weighted LMP from 2004 through 2008.

Figure 2-11 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2004 to 2008



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

Table 2-54 shows PJM zonal real-time, load-weighted, average LMP for 2007 and 2008. The largest zonal increase was in the AECO Control Zone which experienced a $19.07, or 26.7 percent, increase over 2007, and the smallest increase was in the ComEd Control Zone which experienced a $4.35, or 8.8 percent, increase over 2007.

Table 2-54 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AECO	$71.48	$90.55	$19.07	26.7%
AEP	$49.60	$56.65	$7.05	14.2%
AP	$61.25	$69.88	$8.63	14.1%
BGE	$75.96	$87.11	$11.15	14.7%
ComEd	$49.28	$53.63	$4.35	8.8%
DAY	$50.08	$57.81	$7.73	15.4%
DLCO	$47.26	$52.45	$5.19	11.0%
Dominion	$72.51	$82.88	$10.37	14.3%
DPL	$69.38	$83.88	$14.50	20.9%
JCPL	$71.90	$86.43	$14.53	20.2%
Met-Ed	$69.36	$79.81	$10.45	15.1%
PECO	$67.14	$80.76	$13.62	20.3%
PENELEC	$57.79	$66.47	$8.68	15.0%
Pepco	$76.74	$87.89	$11.15	14.5%
PPL	$66.13	$77.79	$11.66	17.6%
PSEG	$70.90	$85.54	$14.64	20.6%
RECO	$70.94	$85.26	$14.32	20.2%

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

Table 2-55 shows the real-time, load-weighted, average LMPs for all or part of the jurisdictions within the PJM footprint during 2007 and 2008[36]. The largest increase was in New Jersey which experienced a $15.21, or 21.3 percent, increase over 2007, and the smallest increase was in Illinois which experienced a $4.35, or 8.8 percent, increase over 2007.

Table 2-55 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
Delaware	$68.17	$82.25	$14.08	20.7%
Illinois	$49.28	$53.63	$4.35	8.8%
Indiana	$48.93	$55.98	$7.05	14.4%
Kentucky	$50.20	$57.45	$7.25	14.4%
Maryland	$76.10	$87.10	$11.00	14.5%
Michigan	$50.16	$58.07	$7.91	15.8%
New Jersey	$71.27	$86.48	$15.21	21.3%
North Carolina	$68.03	$80.28	$12.25	18.0%
Ohio	$48.79	$55.90	$7.11	14.6%
Pennsylvania	$62.60	$73.29	$10.69	17.1%
Tennessee	$50.00	$56.67	$6.67	13.3%
Virginia	$69.33	$79.65	$10.32	14.9%
West Virginia	$51.52	$58.21	$6.69	13.0%
District of Columbia	$75.34	$86.68	$11.34	15.1%

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

Fuel Cost

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[37] To account for the changes in fuel cost between 2007 and 2008, the 2008 load-weighted LMP was adjusted to reflect the change in the daily price of fuels used by marginal units and the change in the amount of load affected by marginal units, using sensitivity factors.[38]

The dominant fuels in PJM all increased in price in 2008. In 2008, the price of 1.5 percent sulfur content per MBtu Central Appalachian coal was 83.0 percent higher than in 2007. The Western

36 The PJM footprint includes 17 control zones. Each control zone is in one or more states or the District of Columbia, but such jurisdictions generally are not entirely covered by PJM control zones. The term jurisdiction is used here to refer to the states in which one or more of these control zones are located. For maps showing the PJM footprint and its control zones, see the *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

37 See the *2008 State of the Market Report*, Volume II, Section 2,"Energy Market, Part 1," at Table 2-32, "Type of fuel used by marginal units: Calendar years 2005 to 2008."

38 For more information, see the *2008 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity Factors."

Rail Powder River Basin coal price was 21.7 percent higher than in 2007. Natural gas prices were 27.0 percent higher in 2008 than in 2007. No. 2 (light) oil prices were 37.9 percent higher and No. 6 (heavy) oil prices were 37.1 percent higher in 2008 than in 2007.

Fuel prices reached their annual peaks in June and July. Since October 2008, the prices for natural gas, light oil and heavy oil were lower than during the corresponding period in 2007. From October to December in 2008, natural gas prices were 6.2 percent lower, No. 2 (light) oil prices were 23.6 percent lower and No. 6 (heavy) oil prices were 36.8 percent lower than the corresponding fuel prices during the same months in 2007. Figure 2-12 shows average, daily delivered coal, natural gas and oil prices for units within PJM.[39]

Figure 2-12 Spot average fuel price comparison: Calendar years 2007 to 2008

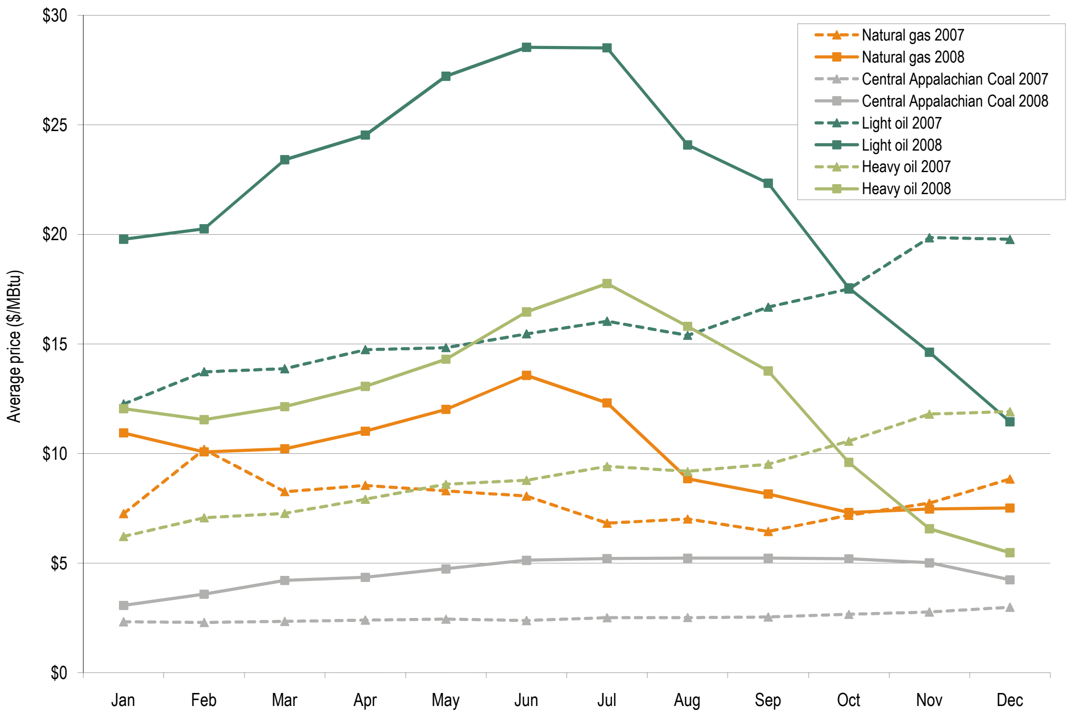


Figure 2-13 shows average, daily settled prices for NO_x and SO_2 emission within PJM. In 2008, NO_x prices were 1.7 percent higher than in 2007. SO_2 prices were 45.9 percent lower in 2008 than in 2007.

The decline in NO_x prices that began in August (Figure 2-13) occurred at about the same time as the issuance of a decision dated August 11, 2008, by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) that vacated the Environmental Protection Agency's Clean Air Interstate Rule (CAIR).[40] CAIR required upwind states to implement control measures to

39 Natural gas prices are the daily cash price for Transco-Z6 (non-New York) adjusted for transportation to the burner tip. Light oil prices are the average of the daily price for No. 2 from the New York Harbor Spot Barge and from the Chicago pipeline and are adjusted for transportation. Heavy oil prices are a daily average of New York Harbor Spot Barge for 0.3 percent, 0.7 percent, 1.0 percent, 2.2 percent and 3.0 percent sulfur content. Coal prices are the 1.5 percent sulfur content per MBtu Central Appalachian coal, price-adjusted for transportation. All fuel prices are from Platts.

40 *North Carolina v. Environmental Protection Agency, et al.*, 531 F.3d 896 (2008).

reduce emissions and created an optional interstate cap and trade program for pollutants, including NO_x. Vacatur (as opposed to remand) suspended the existence of the program. The D.C. Circuit reversed its decision en banc on December 23, 2008, remanding CAIR to the EPA for an overhaul, but reinstating the program in the interim.[41]

As a result of the D.C. Circuit's reversal of its decision to vacate CAIR, the EPA implemented the program on schedule. The first phase of CAIR went into effect on January 1, 2009, mandating emissions cuts of NO_x. Mandates for SO_2 emissions will commence on January 1, 2010. The D.C. Circuit's order that that the EPA significantly revise CAIR remains, but there is no deadline.

Figure 2-13 Spot average emission price comparison: Calendar years 2007 to 2008

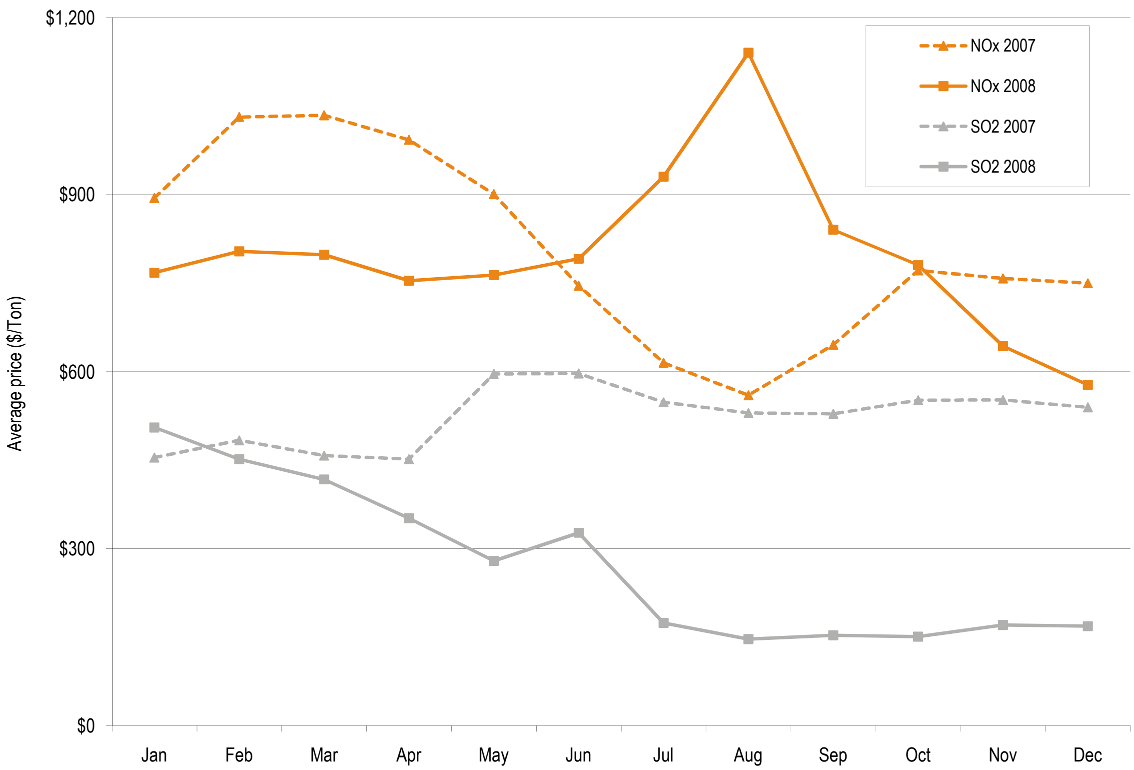


Table 2-56 compares the 2008 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2007 load-weighted, average LMP. The load-weighted, average LMP for 2008 was 15.4 percent higher than the load-weighted, average LMP for 2007. The fuel-cost-adjusted, load-weighted, average LMP in 2008 was 16.0 percent lower than the load-weighted LMP in 2007. If fuel costs for the year 2008 had been the same as for 2007, the 2008 load-weighted LMP would have been lower, $51.79 per MWh instead of $71.13 per MWh. Higher coal, gas and oil prices in 2008 resulted in higher prices in 2008 than would have occurred if fuel prices had remained at their 2007 levels. Net fuel cost increases were the reason for the higher LMPs in 2008.

41 550 F.3d 1176.

Table 2-56 PJM annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2007 Load-Weighted LMP	2008 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$61.66	$51.79	(16.0%)

Components of Real-Time, Load-Weighted LMP

Observed LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal units generally determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs and markup. As a result, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Spot fuel prices were used, and emission costs were calculated using spot prices for NO_x and SO_2 emission credits and unit-specific emission rates. The emission costs for NO_x are applicable for the May to September ozone season and the emission costs for SO_2 are applicable throughout the year.

Table 2-57 shows that 50.7 percent of the annual, load-weighted LMP was the result of gas costs; 37.2 percent was the result of coal costs and 2.5 percent was the result of the cost of SO_2 emission allowances. Markup was 2.9 percent of LMP. The fuel-related components of LMP reflect the impact of the cost of the identified fuel on LMP rather than the full impact of units burning that fuel on LMP.

As a result of the way in which LMP is calculated, there are differences between the components of LMP associated with individual unit characteristics, e.g. fuel costs and VOM, and observed LMP. This total net difference in 2008 was -$1.77 per MWh. (Numbers in parentheses in the table are negative.) The components of this difference are listed in Table 2-57.[42]

42 The technical reasons for each of these components are explained in the *2008 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity Factors."

Table 2-57 Components of PJM annual, load-weighted, average LMP: Calendar year 2008

Element	Contribution to LMP	Percent
Gas	$36.03	50.7%
Coal	$26.44	37.2%
Oil	$2.56	3.6%
Uranium	$0.00	0.0%
FMU Adder	$0.30	0.4%
SO2	$1.80	2.5%
NOX	$0.72	1.0%
VOM	$3.00	4.2%
Markup	$2.04	2.9%
Offline CT Adder	$0.34	0.5%
UDS Override Differential	($1.79)	(2.5%)
Dipatch Differential	$0.03	0.0%
Small DFAX adjustment	($0.20)	(0.3%)
Flow violation adjustment	$0.01	0.0%
Unit LMP Differential	($0.27)	(0.4%)
NA	$0.12	0.2%
LMP	$71.13	100.0%

PJM Retroactively Changed Real-Time LMP for September 4, 2008

On September 24, 2008, PJM retroactively changed Real-Time, LMP for September 4, 2008, for hours ending 15 through 21 and the hour ending 24, and notified PJM members by email:[43]

> The data file containing the real-time LMP for September 4th, 2008 has been reposted. After review of this data, PJM identified several units that were incorrectly logged on their price-based schedule that should have been offer-capped based on market power mitigation rules specified in the Tariff. These units then set price in real-time which caused incorrect LMP prices in several hours on this day. PJM has corrected these logging mistakes, recalculated, and reposted Real-Time LMPs for hours where this occurred. The only hours affected are hours ending 15 through 21, and 24 on September 4th, 2008. In addition, all settlement reports posted in the MSRS system for this day will be updated as soon as possible to reflect the change in Real-Time LMPs.

Table 2-58 shows zonal, real-time, simple average LMPs for the affected hours before and after the changes. The largest positive zonal impact occurred in the Dominion Control Zone, which experienced an average $2.43 per MWh increase as a result of the change, and the smallest positive zonal impact occurred in the PPL Control Zone which experienced an average $0.13 per MWh increase as a result of the change. The largest negative zonal impact occurred in the PECO

43 The email was sent to PJM-MRC at Wednesday, September 24, 2008 11:18 AM. The subject of the message is “Real-time LMP File Posting Update - September 4, 2008 Real-time Prices – Corrected.”

Control Zone, which experienced an average $2.28 per MWh decrease as a result of the change, and the smallest negative zonal impact occurred in the DPL Control Zone, which experienced an average $0.15 per MWh decrease as a result of the change.

Table 2-58 Zonal average LMP: Hours ending 15 through 21 and hour ending 24

	RT LMP Before Change	RT LMP After Change	Difference	Difference as Percent of LMP Before Change
AECO	$268.97	$268.11	($0.87)	(0.3%)
AEP	$64.03	$63.60	($0.43)	(0.7%)
AP	$140.92	$141.85	$0.93	0.7%
BGE	$178.44	$179.17	$0.73	0.4%
ComEd	$51.10	$50.90	($0.21)	(0.4%)
DAY	$60.83	$60.56	($0.27)	(0.5%)
DLCO	$101.39	$101.86	$0.47	0.5%
Dominion	$141.52	$143.95	$2.43	1.7%
DPL	$265.64	$265.49	($0.15)	(0.1%)
JCPL	$203.45	$202.74	($0.72)	(0.4%)
Met-Ed	$169.36	$167.79	($1.57)	(0.9%)
PECO	$404.47	$402.20	($2.28)	(0.6%)
PENELEC	$125.61	$125.91	$0.30	0.2%
Pepco	$170.50	$171.05	$0.54	0.3%
PPL	$156.12	$156.25	$0.13	0.1%
PSEG	$215.53	$214.71	($0.81)	(0.4%)
RECO	$161.07	$160.72	($0.35)	(0.2%)
PJM	$150.21	$150.20	($0.02)	(0.0%)

Table 2-59 shows the real time, simple average LMPs at the PJM hubs for affected hours before and after the change. The largest positive impact occurred for the Dominion Hub, which experienced an average $3.68 per MWh increase as a result of the changes, and the smallest positive impact occurred for the West Int Hub and Western Hub, which experienced an average $0.60 per MWh decrease as a result of the change. The largest negative impact occurred for the Eastern Hub, which experienced an average $1.12 per MWh decrease as a result of the change, and the smallest negative impact occurred for the Chicago Gen Hub which experienced an average $0.20 decrease as a result of the changes.

Table 2-59 Hub average LMP: Hours ending 15 through 21 and hour ending 24

	RT LMP Before Change	RT LMP After Change	Difference	Difference as Percent of LMP Before Change
AEP GEN HUB	$51.96	$51.70	($0.26)	(0.5%)
AEP-DAYTON HUB	$61.29	$61.03	($0.26)	(0.4%)
CHICAGO GEN HUB	$49.11	$48.90	($0.20)	(0.4%)
CHICAGO HUB	$51.43	$51.22	($0.21)	(0.4%)
DOMINION HUB	$127.17	$130.85	$3.68	2.9%
EASTERN HUB	$323.79	$322.67	($1.12)	(0.3%)
N ILLINOIS HUB	$50.44	$50.23	($0.21)	(0.4%)
NEW JERSEY HUB	$218.14	$217.37	($0.77)	(0.4%)
OHIO HUB	$59.76	$59.53	($0.24)	(0.4%)
WEST INT HUB	$86.74	$87.34	$0.60	0.7%
WESTERN HUB	$145.60	$146.20	$0.60	0.4%

Table 2-60 shows real-time, simple average LMPs at the top ten buses for affected hours before and after the change. The largest positive bus-specific impact occurred at the Mt Laurel 413 KV TX1 bus, in the PSEG Control Zone, which experienced an average $29.86 per MWh increase as a result of the changes, and the largest negative bus-specific impact occurred at the Bonsack 138 KV T1 bus, in the AEP Control Zone, which experienced an average $24.10 decrease as a result of the changes.

Table 2-60 Bus average LMP: Hours ending 15 through 21 and hour ending 24

	RT LMP Before Change	RT LMP After Change	Difference	Difference as Percent of LMP Before Change
BARNJNDP115 KV TX1	$234.36	$258.74	$24.38	10.4%
BLBRANDP69 KV TX1	$204.82	$223.81	$18.99	9.3%
BONSACK 138 KV T1	$112.46	$88.36	($24.10)	(21.4%)
DRYBURG 115 KV TX1	$265.16	$295.01	$29.85	11.3%
DRYBURG 115 KV TX2	$265.16	$295.01	$29.85	11.3%
MTLAURE413 KV TX1	$265.11	$294.97	$29.86	11.3%
NIAGARA212 KV LOAD	$99.68	$89.82	($9.86)	(9.9%)
ROANOKE 138 KV T2	$98.56	$88.70	($9.87)	(10.0%)
VINTON 138 KV T1	$103.67	$88.84	($14.83)	(14.3%)
VINTON 138 KV T2	$103.67	$88.84	($14.83)	(14.3%)

Day-Ahead LMP

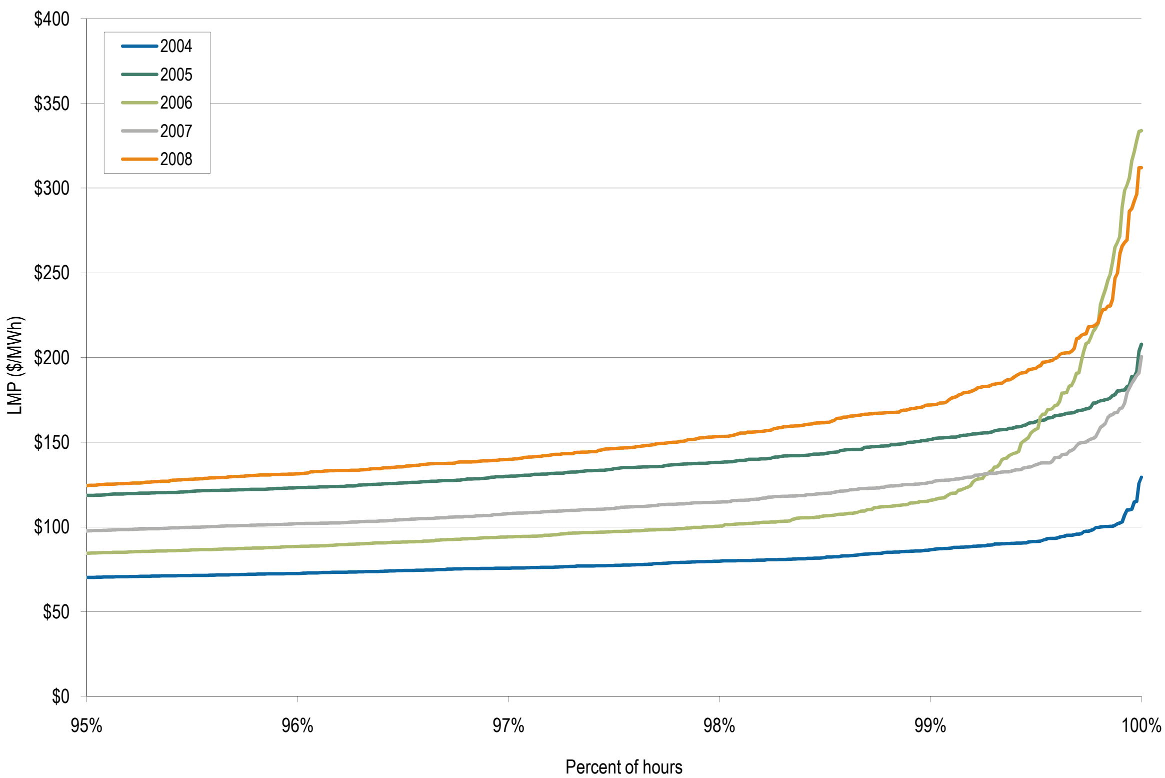
Day-ahead LMP is the hourly LMP for the PJM Day-Ahead Energy Market.

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-14 presents day-ahead price duration curves for hours above the 95th percentile from 2004 to 2008. As Figure 2-14 shows, day-ahead LMP was less than $100 per MWh during 95 percent or more of the hours for the years 2004, 2006 and 2007 and less than $150 during 95 percent or more of the hours for 2005 and 2008.

Figure 2-14 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2004 to 2008



PJM Day-Ahead, Annual Average LMP

Table 2-61 shows the PJM day-ahead annual, simple average LMP for the five-year period 2004 to 2008. The system simple average LMP for 2008 was 20.9 percent higher than the 2007 annual average, $66.12 per MWh versus $54.67 per MWh.

Table 2-61 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2004 to 2008

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2004	$41.43	$40.36	$16.60	NA	NA	NA
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%

Zonal Day-Ahead, Annual Average LMP

Table 2-62 shows PJM zonal day-ahead, simple average LMP for 2007 and 2008. The largest zonal increase was in the JCPL Control Zone which experienced a $16.56, or 26.2 percent, increase over 2007 and the smallest increase was in the ComEd Control Zone which experienced a $5.15, or 11.4 percent, increase over 2007.

Table 2-62 Zonal day-ahead, simple average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AECO	$62.96	$78.99	$16.03	25.5%
AEP	$45.55	$53.61	$8.06	17.7%
AP	$54.88	$65.09	$10.21	18.6%
BGE	$65.37	$80.70	$15.33	23.5%
ComEd	$45.35	$50.50	$5.15	11.4%
DAY	$45.29	$53.53	$8.24	18.2%
DLCO	$43.75	$50.92	$7.17	16.4%
Dominion	$63.42	$75.60	$12.18	19.2%
DPL	$61.95	$77.95	$16.00	25.8%
JCPL	$63.18	$79.74	$16.56	26.2%
Met-Ed	$61.62	$75.54	$13.92	22.6%
PECO	$61.25	$76.23	$14.98	24.5%
PENELEC	$52.97	$65.11	$12.14	22.9%
Pepco	$66.44	$81.26	$14.82	22.3%
PPL	$60.00	$74.25	$14.25	23.8%
PSEG	$63.94	$79.77	$15.83	24.8%
RECO	$63.37	$78.08	$14.71	23.2%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-63 shows PJM's day-ahead, simple average LMPs for 2007 and 2008, by jurisdiction. The largest increase was in New Jersey which experienced a $16.06, or 25.2 percent, increase over 2007, and the smallest increase was in Illinois which experienced a $5.15, or 11.4 percent, increase over 2007.

Table 2-63 Day-ahead, simple average LMP (Dollars per MWh) by state: Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
Delaware	$61.36	$76.88	$15.52	25.3%
Illinois	$45.35	$50.50	$5.15	11.4%
Indiana	$45.49	$53.58	$8.09	17.8%
Kentucky	$45.42	$53.36	$7.94	17.5%
Maryland	$65.46	$80.01	$14.55	22.2%
Michigan	$46.01	$54.48	$8.47	18.4%
New Jersey	$63.62	$79.68	$16.06	25.2%
North Carolina	$59.91	$71.66	$11.75	19.6%
Ohio	$44.72	$52.85	$8.13	18.2%
Pennsylvania	$56.88	$70.04	$13.16	23.1%
Tennessee	$46.52	$54.24	$7.72	16.6%
Virginia	$61.09	$73.01	$11.92	19.5%
West Virginia	$46.66	$54.67	$8.01	17.2%
District of Columbia	$66.41	$81.04	$14.63	22.0%

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead demand MWh cleared during a year. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMPs, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load and decrement bids.

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

Table 2-64 shows the PJM day-ahead, annual, load-weighted, average LMP for the five-year period 2004 to 2008. The day-ahead, load-weighted, average LMP for 2008 was 21.4 percent higher than the 2007 annual, load-weighted, average, at $70.25 per MWh versus $57.88 per MWh.

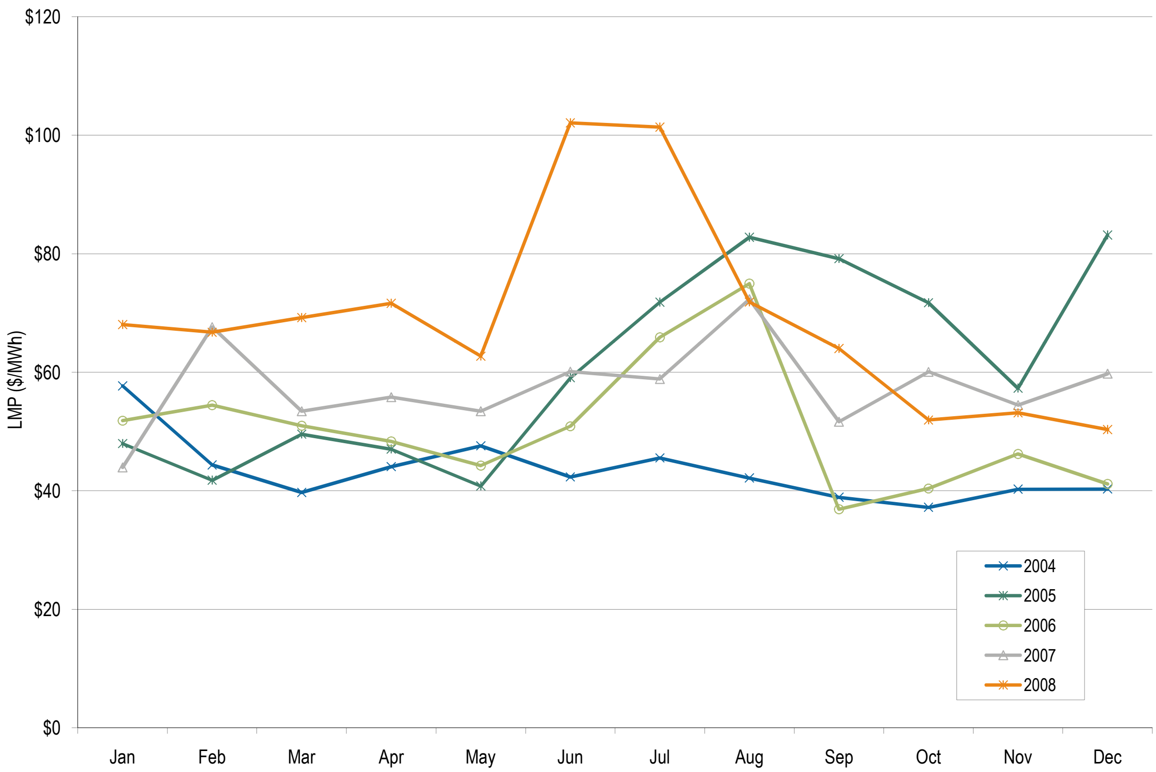
Table 2-64 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2004 to 2008

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2004	$42.87	$41.96	$16.32	NA	NA	NA
2005	$62.50	$54.74	$31.72	45.8%	30.5%	94.4%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.7%)	(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%	32.5%

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

Figure 2-15 shows the PJM day-ahead, monthly, load-weighted LMP from 2004 through 2008.

Figure 2-15 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2004 to 2008



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-65 shows PJM's zonal day-ahead, load-weighted, average LMPs for 2007 and 2008. The largest zonal increase was in the AECO Control Zone which experienced an $19.66, or 28.4 percent, increase over 2007, and the smallest increase was in the ComEd Control Zone which experienced a $6.56, or 13.9 percent, increase over 2007.

Table 2-65 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AECO	$69.11	$88.77	$19.66	28.4%
AEP	$48.26	$56.48	$8.22	17.0%
AP	$57.34	$67.94	$10.60	18.5%
BGE	$70.22	$87.50	$17.28	24.6%
ComEd	$47.27	$53.83	$6.56	13.9%
DAY	$48.43	$57.04	$8.61	17.8%
DLCO	$46.99	$54.33	$7.34	15.6%
Dominion	$68.08	$81.98	$13.90	20.4%
DPL	$66.84	$84.24	$17.40	26.0%
JCPL	$68.34	$86.65	$18.31	26.8%
Met-Ed	$65.36	$79.88	$14.52	22.2%
PECO	$65.21	$81.44	$16.23	24.9%
PENELEC	$55.44	$67.56	$12.12	21.9%
Pepco	$70.50	$86.36	$15.86	22.5%
PPL	$63.52	$78.08	$14.56	22.9%
PSEG	$68.01	$85.82	$17.81	26.2%
RECO	$68.88	$84.73	$15.85	23.0%

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

Table 2-66 shows PJM's day-ahead, load-weighted, average LMPs for 2007 and 2008 by jurisdiction. The largest increase was in the New Jersey which experienced an $18.14, or 26.6 percent, increase over 2007, and the smallest increase was in Illinois which experienced a $6.56, or 13.9 percent, increase over 2007.

Table 2-66 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
Delaware	$65.99	$82.99	$17.00	25.8%
Illinois	$47.27	$53.83	$6.56	13.9%
Indiana	$48.26	$56.53	$8.27	17.1%
Kentucky	$48.09	$56.02	$7.93	16.5%
Maryland	$70.07	$85.98	$15.91	22.7%
Michigan	$48.73	$57.83	$9.10	18.7%
New Jersey	$68.25	$86.39	$18.14	26.6%
North Carolina	$65.10	$78.13	$13.03	20.0%
Ohio	$47.43	$55.72	$8.29	17.5%
Pennsylvania	$60.10	$73.58	$13.48	22.4%
Tennessee	$49.30	$56.50	$7.20	14.6%
Virginia	$65.42	$78.63	$13.21	20.2%
West Virginia	$49.33	$57.56	$8.23	16.7%
District of Columbia	$70.08	$85.66	$15.58	22.2%

Marginal Losses

Marginal losses are the incremental change in system real power losses caused by changes in the system load and generation patterns.[44] Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[45] The primary benefit of a marginal loss mechanism is that it more accurately models the physical reality of power system losses. More accurate models permit increased efficiency and optimize asset utilization. One characteristic of marginal loss modeling is that it creates a separate marginal loss price for every location on the power grid.

Table 2-67 shows the PJM real-time, simple average LMP components, including the loss component, for calendar years 2006 to 2008. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. Table 2-67 shows a $0.04 loss component included at the PJM price. The PJM price is weighted with accounting load, which differs from the state-estimated load used in determination of the energy component. The $0.04 loss component of the average PJM system price results from these different weights. The $2.08 and $1.00 congestion component of the average PJM system price for 2006 and 2007 respectively, resulted from the fact that the distributed load reference bus did not go into effect until June 1, 2007.

Table 2-67 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2008

	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	$66.29	$0.06	$0.04

44 For additional information, see the *2008 State of the Market Report*, Volume II, Appendix J, "Marginal Losses."

45 For additional information, see PJM. "Open Access Transmission Tariff" (December 10, 2007), Section 3.4, Original Sheet No. 388G.

Table 2-68 shows the zonal real-time, simple average LMP components, including the loss component, for calendar years 2007 and 2008.

Table 2-68 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2007 and 2008

	2007				2008			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$65.02	$56.56	$6.42	$2.04	$80.70	$66.29	$10.77	$3.64
AEP	$46.55	$56.56	($8.80)	($1.21)	$53.42	$66.29	($10.46)	($2.42)
AP	$57.45	$56.56	$1.33	($0.44)	$65.85	$66.29	$0.29	($0.73)
BGE	$69.79	$56.56	$12.08	$1.15	$80.05	$66.29	$11.06	$2.69
ComEd	$45.71	$56.56	($9.42)	($1.43)	$49.38	$66.29	($13.46)	($3.46)
DAY	$46.47	$56.56	($9.54)	($0.55)	$53.68	$66.29	($11.18)	($1.43)
DLCO	$43.93	$56.56	($11.13)	($1.50)	$48.81	$66.29	($14.47)	($3.01)
Dominion	$66.75	$56.56	$9.89	$0.30	$75.87	$66.29	$8.76	$0.82
DPL	$64.15	$56.56	$6.09	$1.50	$77.20	$66.29	$7.69	$3.21
JCPL	$65.74	$56.56	$7.36	$1.82	$78.80	$66.29	$8.64	$3.87
Met-Ed	$64.57	$56.56	$7.32	$0.69	$74.70	$66.29	$6.51	$1.90
PECO	$62.60	$56.56	$4.82	$1.22	$75.07	$66.29	$6.11	$2.67
PENELEC	$54.80	$56.56	($1.46)	($0.30)	$63.37	$66.29	($2.33)	($0.59)
Pepco	$70.33	$56.56	$13.00	$0.77	$80.45	$66.29	$12.40	$1.76
PPL	$62.02	$56.56	$4.89	$0.57	$73.35	$66.29	$5.50	$1.55
PSEG	$65.92	$56.56	$7.43	$1.93	$79.14	$66.29	$8.92	$3.92
RECO	$64.85	$56.56	$6.50	$1.79	$77.46	$66.29	$7.62	$3.54

Table 2-69 shows the real-time, annual, simple average LMP loss component at the PJM hubs for 2008, for each hub in PJM.

Table 2-69 Hub real-time, simple average LMP components (Dollars per MWh): 2008

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$50.35	$66.29	($11.29)	($4.66)
AEP-DAY Hub	$53.05	$66.29	($10.71)	($2.54)
Chicago Gen Hub	$48.60	$66.29	($13.32)	($4.37)
Chicago Hub	$49.43	$66.29	($13.42)	($3.44)
Dominion Hub	$73.89	$66.29	$7.37	$0.23
Eastern Hub	$77.15	$66.29	$7.17	$3.68
N Illinois Hub	$48.99	$66.29	($13.45)	($3.85)
New Jersey Hub	$79.02	$66.29	$8.92	$3.81
Ohio Hub	$53.09	$66.29	($10.84)	($2.36)
West Interface Hub	$58.40	$66.29	($5.35)	($2.55)
Western Hub	$68.53	$66.29	$2.80	($0.57)

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

Table 2-70 shows the real-time, annual, load-weighted, average LMP components for PJM and its 17 control zones for 2008.

Table 2-70 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): 2008

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$90.55	$72.70	$13.83	$4.02
AEP	$56.65	$69.92	($10.74)	($2.53)
AP	$69.88	$70.30	$0.36	($0.79)
BGE	$87.11	$71.70	$12.43	$2.98
ComEd	$53.63	$70.52	($13.33)	($3.56)
DAY	$57.81	$70.68	($11.45)	($1.43)
DLCO	$52.45	$70.79	($15.10)	($3.23)
Dominion	$82.88	$72.04	$9.93	$0.91
DPL	$83.88	$72.07	$8.26	$3.55
JCPL	$86.43	$73.19	$9.03	$4.21
Met-Ed	$79.81	$70.97	$6.84	$2.00
PECO	$80.76	$71.44	$6.47	$2.84
PENELEC	$66.47	$69.60	($2.48)	($0.64)
Pepco	$87.89	$71.90	$14.06	$1.94
PPL	$77.79	$70.47	$5.67	$1.65
PSEG	$85.54	$71.95	$9.41	$4.19
RECO	$85.26	$73.69	$7.73	$3.85
PJM	$71.13	$71.02	$0.06	$0.05

Table 2-71 shows the PJM day-ahead, simple average LMP components, including the loss component, for calendar years 2006 to 2008. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. In the Day-Ahead Energy Market, the distributed load reference bus is weighted with fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed-demand-weighted price. The day-ahead system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price; however, in the Day-Ahead Energy Market the energy component and the PJM system price are not equal, but the loss component and the congestion component have only a small effect. This is due to the use of all types of demand to weight the PJM price and not fixed demand only.

Table 2-71 PJM day-ahead, simple average LMP components (Dollars per MWh): 2006 to 2008

	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)

Table 2-72 shows the zonal day-ahead, simple average LMP components, including the loss component, for calendar years 2007 and 2008.[46]

Table 2-72 Zonal day-ahead, simple average LMP components (Dollars per MWh): 2007 and 2008

	2007				2008			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$62.96	$54.60	$6.27	$2.09	$78.99	$66.43	$7.93	$4.63
AEP	$45.55	$54.60	($7.59)	($1.46)	$53.61	$66.43	($9.56)	($3.26)
AP	$54.88	$54.60	$0.77	($0.49)	$65.09	$66.43	($0.50)	($0.84)
BGE	$65.37	$54.60	$9.50	$1.27	$80.70	$66.43	$10.96	$3.31
ComEd	$45.35	$54.60	($7.80)	($1.45)	$50.50	$66.43	($11.37)	($4.56)
DAY	$45.29	$54.60	($8.12)	($1.19)	$53.53	$66.43	($10.04)	($2.86)
DLCO	$43.75	$54.60	($9.22)	($1.64)	$50.92	$66.43	($11.77)	($3.73)
Dominion	$63.42	$54.60	$8.42	$0.39	$75.60	$66.43	$8.07	$1.10
DPL	$61.95	$54.60	$5.72	$1.63	$77.95	$66.43	$7.63	$3.90
JCPL	$63.18	$54.60	$6.49	$2.09	$79.74	$66.43	$7.92	$5.39
Met-Ed	$61.62	$54.60	$6.24	$0.77	$75.54	$66.43	$6.59	$2.53
PECO	$61.25	$54.60	$5.01	$1.63	$76.23	$66.43	$5.93	$3.87
PENELEC	$52.97	$54.60	($1.14)	($0.50)	$65.11	$66.43	($0.91)	($0.41)
Pepco	$66.44	$54.60	$10.83	$1.00	$81.26	$66.43	$12.28	$2.55
PPL	$60.00	$54.60	$4.75	$0.65	$74.25	$66.43	$5.62	$2.20
PSEG	$63.94	$54.60	$7.05	$2.29	$79.77	$66.43	$7.76	$5.58
RECO	$63.37	$54.60	$6.77	$2.00	$78.08	$66.43	$6.55	$5.10

46 For some zones, energy component plus congestion component plus loss component may not equal the total day-ahead LMP because the total is based on the underlying data, which is not rounded.

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

Table 2-73 shows zonal and PJM day-ahead, annual, load-weighted, average LMP components for calendar year 2008.

Table 2-73 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): 2008

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$88.77	$73.92	$9.49	$5.37
AEP	$56.48	$69.68	($9.78)	($3.42)
AP	$67.94	$69.43	($0.58)	($0.91)
BGE	$87.50	$71.67	$12.14	$3.69
ComEd	$53.83	$69.83	($11.34)	($4.66)
DAY	$57.04	$70.32	($10.30)	($2.98)
DLCO	$54.33	$70.51	($12.18)	($4.00)
Dominion	$81.98	$71.77	$9.02	$1.20
DPL	$84.24	$71.97	$7.97	$4.29
JCPL	$86.65	$72.69	$8.16	$5.80
Met-Ed	$79.88	$70.51	$6.74	$2.63
PECO	$81.44	$71.24	$6.06	$4.14
PENELEC	$67.56	$68.65	($0.72)	($0.38)
Pepco	$86.36	$70.52	$13.10	$2.74
PPL	$78.08	$70.13	$5.66	$2.29
PSEG	$85.82	$71.93	$7.93	$5.97
RECO	$84.73	$72.81	$6.43	$5.49
PJM	$70.25	$70.56	($0.08)	($0.22)

Marginal Loss Accounting

With the implementation of marginal loss pricing, PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP (loss LMP). Each PJM member is charged for the cost of losses on the transmission system, based on the difference between the loss LMP at the location where the PJM member injects energy and the loss LMP where the PJM member withdraws energy.

More specifically, total loss charges are equal to the load loss payments minus generation loss credits, plus explicit loss charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

- **Day-Ahead, Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead, load loss payments are calculated using MW and the load bus loss component of LMP (loss LMP), the decrement bid loss LMP or the loss LMP at the source of the sale transaction, as applicable.

- **Day-Ahead, Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead, generation loss credits are calculated using MW and the generator bus loss LMP, the increment offer loss LMP or the loss LMP at the sink of the purchase transaction, as applicable.

- **Balancing, Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- **Balancing, Generation, Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- **Explicit Loss Charges.** Explicit loss charges are the net loss charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and loss LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss charges equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time loss LMP at the transactions' sources and sinks.

Monthly Marginal Loss Costs

Table 2-74 shows a monthly summary of marginal loss costs by type for 2008. Marginal loss costs totaled $2.493 billion. The highest monthly loss cost was in July and totaled $365.7 million or 14.7 percent of the total. The majority of the marginal loss costs was in the Day-Ahead Energy Market and totaled $2.561 billion. The day-ahead costs were offset, in part, by a total of -$68 million in the balancing market. The overcollected portion of transmission losses that was credited back to load plus exports as of December 31, 2008, was $1.309 billion or 52.5 percent of the total losses. In determining the overcollected loss amount, PJM accumulates the day-ahead and balancing transmission loss charges paid by all customer accounts each hour, subtracts the spot market energy value of the actual transmission loss MWh during that hour, and allocates this amount as transmission loss credits each hour.[47]

Table 2-74 Marginal loss costs by type (Dollars (Millions)): 2008

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$62.7	($154.5)	$10.1	$227.3	($1.7)	$1.5	($1.7)	($4.9)	$222.4
Feb	$52.7	($136.8)	$9.1	$198.7	($1.3)	($1.0)	($3.2)	($3.5)	$195.2
Mar	$55.1	($125.2)	$11.3	$191.7	($1.7)	$0.6	($4.3)	($6.6)	$185.1
Apr	$53.8	($116.8)	$12.8	$183.4	($2.9)	$2.0	($3.4)	($8.3)	$175.1
May	$53.0	($104.6)	$6.6	$164.2	($3.0)	$1.0	$0.4	($3.6)	$160.6
Jun	$93.1	($227.0)	$12.6	$332.7	($4.1)	($0.7)	($3.4)	($6.7)	$326.0
Jul	$103.3	($263.8)	$10.9	$378.1	($8.0)	$0.6	($3.7)	($12.4)	$365.7
Aug	$64.6	($162.3)	$11.9	$238.8	($2.3)	($1.3)	($5.4)	($6.4)	$232.4
Sep	$51.0	($121.2)	$13.2	$185.4	($0.9)	($0.4)	($6.3)	($6.8)	$178.6
Oct	$34.0	($99.9)	$11.7	$145.6	($1.8)	($2.4)	($4.8)	($4.2)	$141.4
Nov	$37.4	($105.3)	$11.5	$154.2	($0.7)	($2.8)	($5.6)	($3.4)	$150.8
Dec	$43.6	($107.4)	$10.4	$161.3	($0.7)	($3.6)	($4.2)	($1.2)	$160.1
Total	$704.3	($1,724.8)	$132.2	$2,561.3	($29.0)	($6.5)	($45.4)	($68.0)	$2,493.3

47 See PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008). Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Zonal Marginal Loss Costs

Table 2-75 shows the marginal loss costs by type in each control zone in 2008. The AEP, ComEd and Dominion control zones had the highest marginal loss costs in 2008, with $505.7 million, $430.6 million and $239.2 million, respectively. Energy flows in PJM are generally from west to east, reflecting the fact that less expensive generation in the western portion of PJM is dispatched to assist in meeting the demand of load centers located in the eastern portion of PJM. Generation supplied from western resources to satisfy eastern load generally results in increased west-to-east transmission flow and increased losses. As may be seen in Table 2-75, the marginal loss generation credits in the western zones are generally greater in magnitude than those of the eastern zones. The characteristics of the marginal loss component of LMP are analogous to those of the congestion component of LMP, or CLMP. Generation congestion credits are generally negative for units located on the unconstrained side of a transmission element, indicating that an increase in output tends to increase the flow of energy across the constrained element. Analogously, the generation marginal loss credits are generally negative for units for which an increase in output tends to increase system losses.

Table 2-75 Marginal loss costs by control zone and type (Dollars (Millions)): 2008

	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	$60.3	$14.8	$0.7	$46.2	($0.2)	($0.5)	($0.2)	$0.1	$46.2
AEP	($89.1)	($595.6)	$21.7	$528.2	($22.9)	$1.1	$1.5	($22.5)	$505.7
AP	($15.0)	($196.6)	$6.9	$188.4	$6.2	$6.7	($1.5)	($1.9)	$186.4
BGE	$96.2	$14.6	$1.8	$83.5	$1.9	($3.6)	($1.5)	$4.0	$87.4
ComEd	($190.0)	($609.0)	$1.4	$420.4	$4.7	($5.8)	($0.3)	$10.2	$430.6
DAY	($9.0)	($90.0)	$2.4	$83.3	($1.2)	$2.9	$0.1	($4.0)	$79.3
DLCO	($52.5)	($104.8)	$0.0	$52.3	($12.2)	$3.8	$0.0	($16.0)	$36.3
Dominion	$103.7	($130.6)	$6.5	$240.8	$3.0	$0.8	($3.7)	($1.6)	$239.2
DPL	$84.7	$19.7	$0.6	$65.6	$1.0	($0.4)	($0.2)	$1.3	$66.9
JCPL	$146.3	$51.6	$4.3	$99.0	$0.9	($1.6)	($3.2)	($0.8)	$98.2
Met-Ed	$40.2	$12.6	$1.9	$29.5	$0.4	($0.6)	$3.8	$4.9	$34.4
PECO	$136.7	$28.8	$0.2	$108.1	($0.1)	$0.5	($0.1)	($0.6)	$107.4
PENELEC	($45.2)	($184.7)	$1.4	$140.9	$0.8	$0.4	$0.9	$1.3	$142.2
PEPCO	$129.2	$50.6	$3.8	$82.4	($0.2)	($1.0)	($2.8)	($2.0)	$80.4
PJM	$8.2	($27.6)	$57.7	$93.4	($12.1)	($16.8)	($26.0)	($21.3)	$72.1
PPL	$88.2	($23.6)	$5.4	$117.2	$0.7	($0.1)	($0.3)	$0.5	$117.7
PSEG	$203.0	$44.8	$14.5	$172.8	$0.2	$7.8	($11.3)	($18.8)	$154.0
RECO	$8.5	$0.2	$1.1	$9.4	$0.1	($0.1)	($0.7)	($0.5)	$8.9
Total	$704.3	($1,724.8)	$132.2	$2,561.3	($29.0)	($6.5)	($45.4)	($68.0)	$2,493.3

Table 2-76 shows the monthly marginal loss cost, by control zone in 2008.

Table 2-76 Monthly marginal loss costs by control zone (Dollars (Millions)): 2008

	Marginal Loss Costs by Control Zone (Millions)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$2.9	$2.6	$2.7	$2.6	$3.7	$7.2	$9.7	$5.3	$2.9	$2.2	$2.3	$2.2	$46.2
AEP	$50.7	$42.6	$37.2	$32.7	$30.5	$68.0	$81.1	$49.4	$36.3	$27.3	$24.5	$25.3	$505.7
AP	$18.4	$15.0	$16.9	$12.1	$10.5	$21.8	$26.8	$16.7	$11.0	$11.4	$13.4	$12.5	$186.4
BGE	$6.6	$6.0	$5.1	$5.0	$5.3	$13.4	$15.1	$9.2	$6.5	$4.2	$5.4	$5.4	$87.4
ComEd	$33.4	$29.6	$33.5	$34.9	$28.6	$52.4	$52.5	$39.4	$33.1	$30.2	$33.0	$30.0	$430.6
DAY	$7.8	$8.0	$5.9	$5.7	$6.8	$10.2	$9.6	$5.9	$5.7	$3.4	$5.0	$5.3	$79.3
DLCO	$3.6	$3.0	$3.7	$1.9	$0.4	$4.5	$4.7	$3.1	$2.8	$2.6	$3.0	$3.1	$36.3
Dominion	$20.3	$16.8	$15.3	$14.2	$14.8	$36.7	$39.2	$24.9	$17.9	$12.6	$12.3	$14.2	$239.2
DPL	$5.4	$4.5	$4.1	$3.9	$3.8	$10.1	$11.5	$7.9	$5.0	$3.2	$3.5	$4.0	$66.9
JCPL	$9.3	$7.9	$8.8	$8.2	$6.9	$12.1	$14.1	$7.7	$6.0	$4.3	$5.8	$7.0	$98.2
Met-Ed	$3.3	$3.4	$3.0	$3.1	$3.2	$4.3	$4.2	$2.7	$2.0	$1.7	$1.6	$1.9	$34.4
PECO	$9.9	$9.2	$8.7	$6.8	$6.7	$15.8	$17.1	$10.1	$6.4	$4.4	$6.1	$6.3	$107.4
PENELEC	$14.9	$12.3	$10.4	$9.3	$9.5	$18.0	$21.9	$14.1	$9.7	$7.3	$6.7	$8.1	$142.2
PEPCO	$6.5	$5.8	$5.1	$5.2	$5.5	$11.2	$12.2	$7.8	$6.4	$5.0	$4.8	$4.7	$80.4
PJM	$3.6	$6.1	$2.9	$7.0	$4.5	$3.3	$5.4	$6.3	$8.1	$6.0	$7.2	$11.7	$72.1
PPL	$12.4	$10.5	$9.2	$7.8	$7.5	$15.4	$16.2	$9.1	$7.7	$6.8	$7.1	$7.9	$117.7
PSEG	$12.7	$11.2	$11.8	$14.1	$11.7	$20.3	$22.9	$12.1	$10.2	$8.5	$8.6	$9.9	$154.0
RECO	$0.6	$0.6	$0.6	$0.7	$0.7	$1.2	$1.5	$0.7	$0.9	$0.4	$0.5	$0.5	$8.9
Total	$222.4	$195.2	$185.1	$175.1	$160.6	$326.0	$365.7	$232.4	$178.6	$141.4	$150.8	$160.1	$2,493.3

Virtual Offers and Bids

The PJM Day-Ahead Energy Market includes the ability to make increment offers (INC) and decrement bids (DEC) at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Since increment offers and decrement bids do not require physical generation or load, they are also referred to as virtual offers and bids. Virtual offers and bids also provide participants the flexibility, for example, to cover one side of a bilateral transaction, hedge day-ahead generator offers or demand bids, and arbitrage day-ahead and real-time prices.

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Market and such offers and bids may each be marginal, based on the way in which the optimization algorithm works.

Table 2-77 shows the frequency with which generation offers, import or export transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month in 2008.[48] Together, increment offers and decrement bids represented 53.1 percent of the marginal bids or offers in 2008.

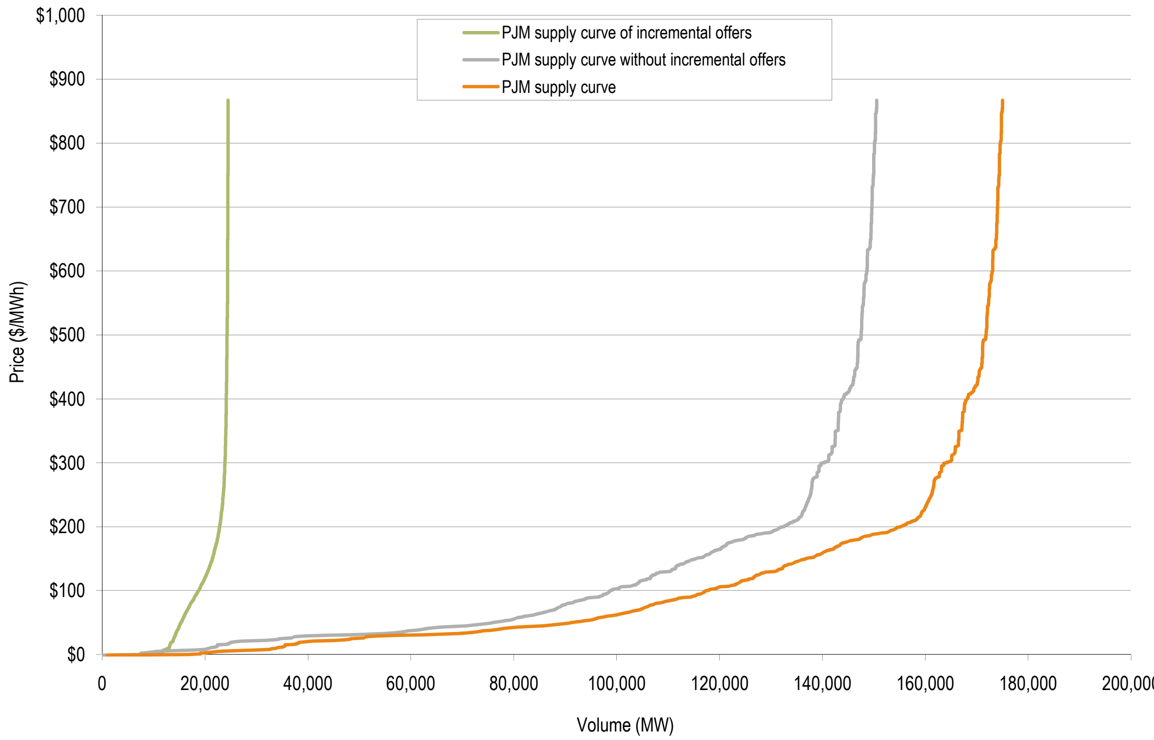
Table 2-77 Type of day-ahead marginal units: Calendar year 2008

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	11.9%	25.3%	44.3%	18.0%	0.4%
Feb	15.0%	25.5%	44.6%	14.3%	0.6%
Mar	15.7%	28.8%	36.2%	18.7%	0.6%
Apr	18.3%	29.1%	32.2%	19.3%	1.0%
May	20.8%	24.3%	32.0%	21.2%	1.6%
Jun	17.5%	23.2%	33.8%	23.8%	1.6%
Jul	14.6%	21.2%	41.2%	21.3%	1.7%
Aug	12.7%	29.4%	38.7%	18.2%	1.0%
Sep	17.8%	31.2%	33.3%	16.7%	1.0%
Oct	18.2%	41.3%	25.7%	13.7%	1.1%
Nov	20.8%	36.3%	26.6%	14.9%	1.4%
Dec	24.8%	34.7%	27.1%	12.3%	1.0%
Annual	16.9%	28.8%	35.1%	18.0%	1.1%

48 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

Figure 2-16 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in June 2008. There were average hourly increment offers of 24,488 MW and average hourly total offers of 175,013 MW for the example day.

Figure 2-16 PJM day-ahead aggregate supply curves: 2008 example day



Price Convergence

When the PJM Day-Ahead Energy Market was introduced, it was expected that competition, exercised substantially through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. But price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to risk that result in a competitive, market-based differential. In addition, convergence in the sense that Day-Ahead and Real-Time prices are equal at individual buses or aggregates is not a realistic expectation. PJM markets do not provide a mechanism that could result in convergence within any individual day as there is at least a one-day lag after any change in system conditions. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. Substantial, virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. (See Figure 2-17.) There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis. (See Figure 2-18.)

As Table 2-78 shows, day-ahead and real-time prices were relatively close, on average, during 2008. Average LMP in the Real-Time Energy Market was $0.28 per MWh or 0.4 percent higher than average LMP in the Day-Ahead Energy Market during 2008.

Table 2-78 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$66.12	$66.40	$0.28	0.4%
Median	$58.93	$55.53	($3.40)	(6.1%)
Standard deviation	$30.87	$38.62	$7.75	20.1%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from volatility in the Real-Time Energy Market that is difficult, or impossible, to anticipate in the Day-Ahead Energy Market. In 2008, real-time prices were higher than day-ahead prices by more than $50 per MWh for 328 hours, more than $100 per MWh for 44 hours and more than $150 per MWh for 7 hours. If the hours with price differences greater than $150 per MWh are excluded, the difference between real-time and day-ahead price is $0.13 per MWh in 2008 rather than $0.28. Although real-time prices were higher than day-ahead prices on average in 2008, real-time prices were lower than day-ahead prices for 59.3 percent of the hours. During hours when real-time prices were higher than day-ahead prices, the average positive difference between them was $19.28 per MWh. During hours when real-time prices were less than day-ahead prices, the average negative difference was -$12.76 per MWh.

Table 2-79 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices from 2000 to 2008. On average, day-ahead prices were lower than real-time prices by $2.90 per MWh during 2007, $1.17 per MWh during 2006, by $0.18 per MWh in 2005 and by $0.97 per MWh in 2004. On average, day-ahead prices were higher than real-time prices by $0.45 per MWh in 2003, by $0.16 per MWh in 2002, by $0.37 per MWh in 2001 and by $1.61 per MWh in 2000.[49]

Table 2-79 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2000 to 2008

Year	Day Ahead	Real Time	Difference	Difference as Percent 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%

49 Since the Day-Ahead Energy Market starts from June 1,2000, the data in 2000 starts from June 1, 2000. However, the starting date for years 2001 to 2008 is January 1.

Table 2-80 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for calendar years 2004 through 2008. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the hourly LMP difference was within a given $50 per MWh price interval. From calendar year 2004 to calendar year 2008, LMP differences occurred predominantly in the range between ($50) per MWh and $50 per MWh. The largest PJM real-time and day-ahead hourly LMP difference occurred in the calendar year of 2006 where an hourly price difference was greater than $500 per MWh. In 2007, the PJM real-time and day-ahead hourly LMP differences are less than $150 per MWh in all but 14 hours. In 2008, the PJM real-time and day-ahead hourly LMP differences are less than $150 per MWh in all but 7 hours.

Table 2-80 Frequency distribution by hours of PJM real-time and day-ahead LMP difference (Dollars per MWh): Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	1	0.01%	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	1	0.01%	1	0.02%	0	0.00%	1	0.01%
($100) to ($50)	5	0.06%	64	0.74%	9	0.13%	33	0.38%	88	1.01%
($50) to $0	4,583	52.23%	5,015	57.99%	5,205	59.54%	4,600	52.89%	5,120	59.30%
$0 to $50	4,146	99.43%	3,471	97.61%	3,372	98.04%	3,827	96.58%	3,247	96.27%
$50 to $100	49	99.99%	190	99.78%	152	99.77%	255	99.49%	284	99.50%
$100 to $150	1	100.00%	17	99.98%	9	99.87%	31	99.84%	37	99.92%
$150 to $200	0	0.00%	2	100.00%	4	99.92%	5	99.90%	4	99.97%
$200 to $250	0	100.00%	0	100.00%	1	99.93%	1	99.91%	2	99.99%
$250 to $300	0	100.00%	0	100.00%	3	99.97%	3	99.94%	0	99.99%
$300 to $350	0	100.00%	0	100.00%	0	99.97%	2	99.97%	1	100.00%
$350 to $400	0	100.00%	0	100.00%	1	99.98%	1	99.98%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	99.98%	1	99.99%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	1	99.99%	1	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	1	100.00%	0	100.00%	0	100.00%

Figure 2-17 shows the hourly differences between day-ahead and real-time LMP in 2008. Although the average difference between the Day-Ahead and Real-Time Energy Market was $0.28 per MWh for the entire year, Figure 2-17 demonstrates the considerable variation, both positive and negative, between day-ahead and real-time prices. The highest difference between real-time and day-ahead LMP was $311.30 per MWh for the hour ended 1600 on June 12, 2008, when the real-time LMP was $483.27 (peak real-time LMP for 2008) and the day-ahead LMP was $171.97.

Figure 2-17 Hourly real-time minus hourly day-ahead LMP: Calendar year 2008

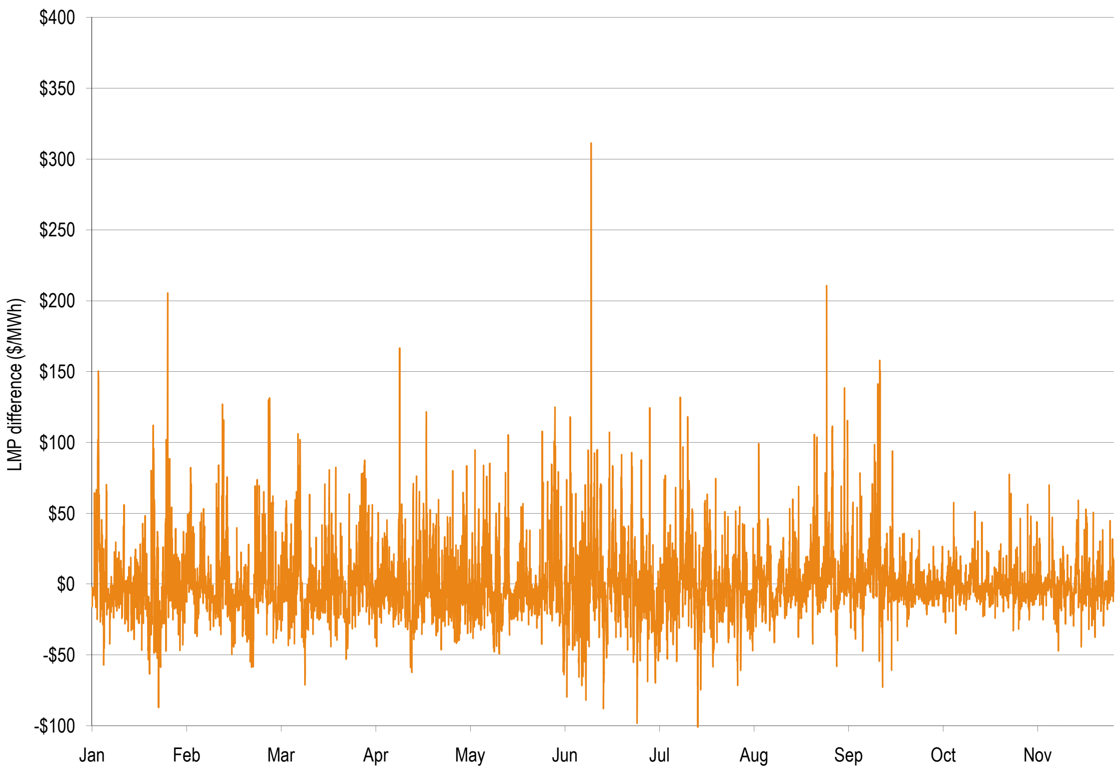


Figure 2-18 shows the monthly average differences between the day-ahead and real-time LMP in 2008. The highest monthly difference was in September.

Figure 2-18 Monthly average of real-time minus day-ahead LMP: Calendar year 2008

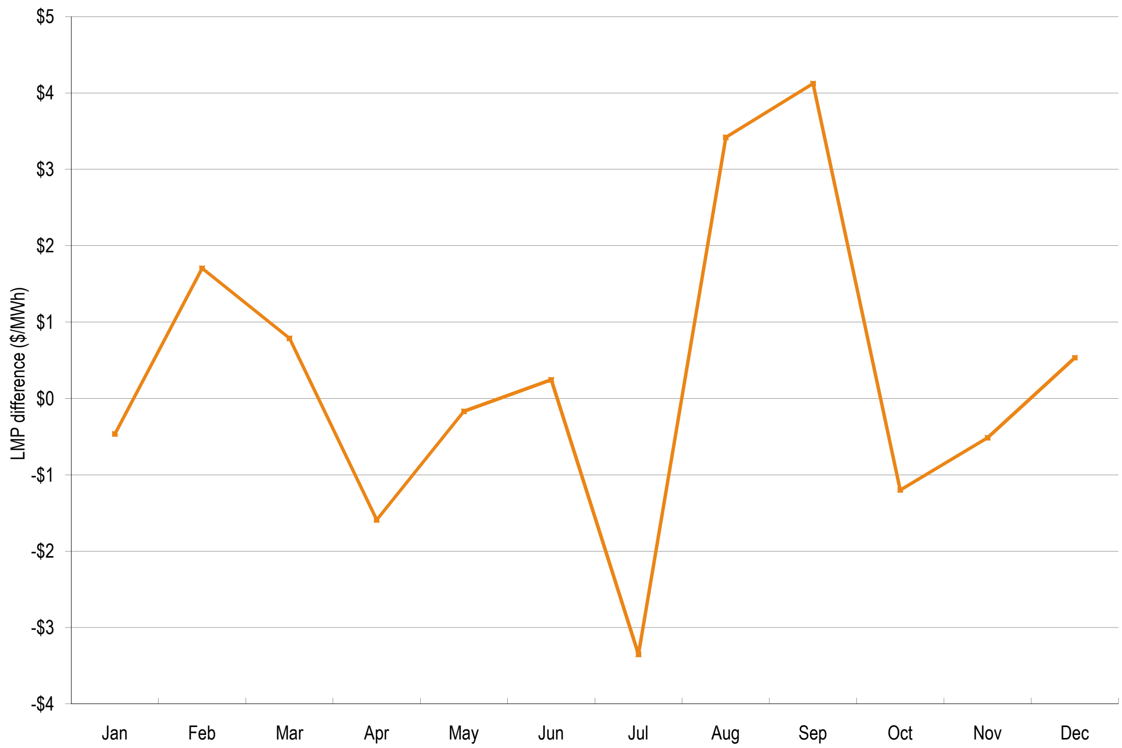
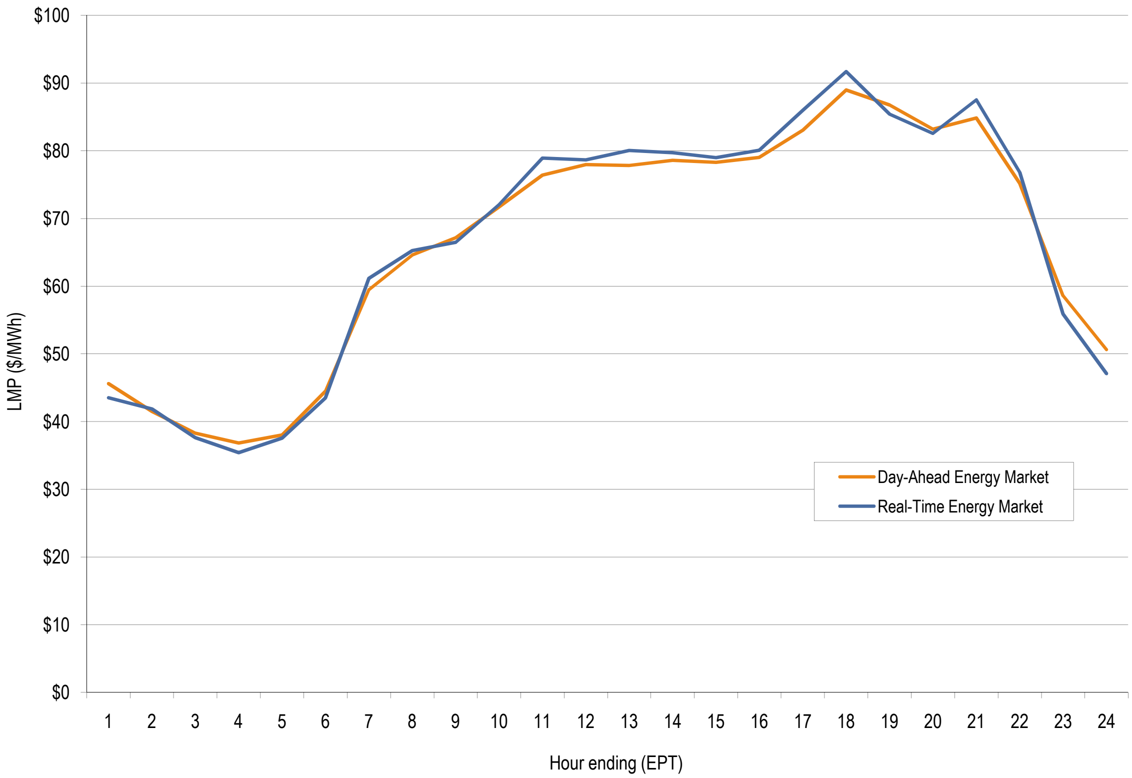


Figure 2-19 shows day-ahead and real-time LMP on an average hourly basis. Real-time average LMP was greater than day-ahead average LMP for 22 out of 24 hours.[50]

Figure 2-19 PJM system hourly average LMP: Calendar year 2008



50 See the *2008 State of the Market Report*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Zonal Price Convergence

Table 2-81 shows 2008 zonal day-ahead and real-time average LMP. The difference between zonal day-ahead and real-time LMP ranged from $2.11 in the DLCO Control Zone, where the day-ahead average LMP was higher than the real-time average LMP, to $1.71 in the AECO Control Zone, where the day-ahead average LMP was lower than the real-time average LMP.

Table 2-81 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$78.99	$80.70	$1.71	2.1%
AEP	$53.61	$53.42	($0.19)	(0.4%)
AP	$65.09	$65.85	$0.76	1.2%
BGE	$80.70	$80.05	($0.65)	(0.8%)
ComEd	$50.50	$49.38	($1.12)	(2.3%)
DAY	$53.53	$53.68	$0.15	0.3%
DLCO	$50.92	$48.81	($2.11)	(4.3%)
Dominion	$75.60	$75.87	$0.27	0.4%
DPL	$77.95	$77.20	($0.75)	(1.0%)
JCPL	$79.74	$78.80	($0.94)	(1.2%)
Met-Ed	$75.54	$74.70	($0.84)	(1.1%)
PECO	$76.23	$75.07	($1.16)	(1.5%)
PENELEC	$65.11	$63.37	($1.74)	(2.7%)
Pepco	$81.26	$80.45	($0.81)	(1.0%)
PPL	$74.25	$73.35	($0.90)	(1.2%)
PSEG	$79.77	$79.14	($0.63)	(0.8%)
RECO	$78.08	$77.46	($0.62)	(0.8%)

Price Convergence by Jurisdiction

Table 2-82 shows the 2008 day-ahead and real-time average LMPs by jurisdiction. The difference between day-ahead and real-time LMP ranged from $1.12 in Illinois, where the day-ahead average LMP was higher than the real-time average LMP, to $0.44 in Maryland, where the day-ahead average LMP was lower than the real-time average LMP.

Table 2-82 Jurisdiction Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$76.88	$76.26	($0.62)	(0.8%)
Illinois	$50.50	$49.38	($1.12)	(2.3%)
Indiana	$53.58	$53.01	($0.57)	(1.1%)
Kentucky	$53.36	$53.80	$0.44	0.8%
Maryland	$80.01	$79.75	($0.26)	(0.3%)
Michigan	$54.48	$54.07	($0.41)	(0.8%)
New Jersey	$79.68	$79.27	($0.41)	(0.5%)
North Carolina	$71.66	$71.69	$0.03	0.0%
Ohio	$52.85	$52.64	($0.21)	(0.4%)
Pennsylvania	$70.04	$68.98	($1.06)	(1.5%)
Tennessee	$54.24	$54.36	$0.12	0.2%
Virginia	$73.01	$73.20	$0.19	0.3%
West Virginia	$54.67	$55.02	$0.35	0.6%
District of Columbia	$81.04	$80.57	($0.47)	(0.6%)

Load and Spot Market

Real-Time Load and Spot Market[51]

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that

51 The analysis here differs from that presented in the *2007 State of the Market Report* in several respects. The billing organization analysis is not included here because it is not a meaningful representation of the ways in which load is served in PJM. Rather, billing organization data reflects decisions by parent organizations about where to incorporate the load serving obligation. In addition, the transfer of load serving obligations via eSchedule bilateral contracts is treated as a transfer of load serving obligation rather than as a bilateral to serve load.

serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts at the same time that it is meeting load. Supply from spot market purchases means that the parent company is not generating enough power from owned plants and/or not purchasing enough power under bilateral contracts to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all PJM parent companies that serve load in the Real-Time Energy Market for each hour. Table 2-83 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2007 and 2008 based on parent company. For 2008, 14.6 percent real-time load was supplied by bilateral contracts, 20.1 percent by spot market purchase and 65.2 percent by self-supply. Compared with 2007, reliance on bilateral contracts decreased 2.0 percentage points, reliance on spot supply increased by 4.2 percentage points and reliance on self-supply decreased by 2.3 percentage points.

Table 2-83 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2007 to 2008

	2007			2008			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	16.5%	14.4%	69.1%	14.3%	17.3%	68.4%	(2.2%)	2.9%	(0.7%)
Feb	16.5%	14.2%	69.3%	15.2%	17.3%	67.5%	(1.3%)	3.1%	(1.8%)
Mar	17.2%	14.6%	68.2%	16.0%	17.1%	66.9%	(1.2%)	2.5%	(1.3%)
Apr	17.4%	14.9%	67.7%	16.6%	18.0%	65.4%	(0.8%)	3.1%	(2.3%)
May	18.2%	14.1%	67.7%	16.0%	18.8%	65.3%	(2.2%)	4.7%	(2.4%)
Jun	16.9%	15.3%	67.8%	13.1%	21.0%	65.9%	(3.8%)	5.7%	(1.9%)
Jul	15.8%	17.2%	66.9%	13.7%	20.6%	65.7%	(2.1%)	3.4%	(1.2%)
Aug	15.5%	16.7%	67.8%	14.9%	22.6%	62.4%	(0.6%)	5.9%	(5.4%)
Sep	15.6%	17.1%	67.3%	14.7%	23.0%	62.2%	(0.9%)	5.9%	(5.1%)
Oct	17.3%	18.2%	64.5%	15.1%	22.7%	62.2%	(2.2%)	4.5%	(2.3%)
Nov	17.1%	17.0%	65.9%	14.8%	22.9%	62.3%	(2.3%)	5.9%	(3.6%)
Dec	15.7%	16.8%	67.5%	12.1%	20.5%	67.4%	(3.6%)	3.7%	(0.1%)
Annual	16.6%	15.9%	67.5%	14.6%	20.1%	65.2%	(2.0%)	4.2%	(2.3%)

Day-Ahead Load and Spot Market[52]

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as generation in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead load (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 2-84 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2007 and 2008, based on parent companies. For 2008, 5.0 percent of day-ahead load was supplied by bilateral contracts, 18.4 percent by spot market purchases, and 76.5 percent by self-supply. Compared with 2007, reliance on bilateral contracts increased by 0.5 percentage points, reliance on spot supply increased by 3.9 percentage points, and reliance on self-supply decreased by 4.5 percentage points.

Table 2-84 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar Years 2007 to 2008

	2007			2008			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	3.9%	12.9%	83.2%	4.2%	15.6%	80.2%	0.3%	2.7%	(3.0%)
Feb	4.1%	13.1%	82.8%	4.5%	16.0%	79.5%	0.4%	2.9%	(3.3%)
Mar	4.2%	13.3%	82.5%	4.7%	16.0%	79.3%	0.5%	2.7%	(3.2%)
Apr	4.5%	12.8%	82.7%	5.0%	16.8%	78.2%	0.5%	4.0%	(4.5%)
May	5.1%	12.5%	82.4%	5.0%	18.2%	76.8%	(0.1%)	5.7%	(5.6%)
Jun	4.5%	14.9%	80.6%	5.5%	20.2%	74.3%	1.0%	5.3%	(6.3%)
Jul	4.2%	15.9%	79.9%	5.6%	20.4%	74.0%	1.4%	4.5%	(5.9%)
Aug	4.1%	15.4%	80.5%	4.9%	20.2%	75.0%	0.8%	4.8%	(5.5%)
Sep	4.8%	15.5%	79.7%	5.4%	19.3%	75.3%	0.6%	3.8%	(4.4%)
Oct	4.9%	16.5%	78.6%	5.4%	20.3%	74.3%	0.5%	3.8%	(4.3%)
Nov	5.2%	15.6%	79.3%	5.6%	18.9%	75.5%	0.4%	3.3%	(3.8%)
Dec	5.2%	15.4%	79.3%	4.6%	19.1%	76.3%	(0.6%)	3.7%	(3.0%)
Annual	4.5%	14.5%	81.0%	5.0%	18.4%	76.5%	0.5%	3.9%	(4.5%)

52 The analysis here differs from that presented in the *2007 State of the Market Report* in several respects. In addition to the changes made in the analysis of the Real-Time Energy Market, the analysis of the Day-Ahead Market treats increment offers as generation and decrement bids as load rather than showing virtuals separately.

Virtual Markets

Increment Offers and Decrement Bids

Any market participant in the PJM Day-Ahead Energy Market can use increment offers and decrement bids as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Table 2-85 shows the average volume of trading in virtual bids per hour, as well as the average total MW values of all virtual bids per hour.

Table 2-85 Monthly volume of cleared and submitted INCs, DECs: calendar year 2008

	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	15,842	22,235	252	490	21,051	29,956	293	592
Feb	15,704	21,725	244	449	20,352	27,978	294	497
Mar	15,131	21,496	242	468	18,477	25,560	298	483
Apr	15,355	22,298	292	566	18,093	25,106	316	543
May	14,344	21,434	431	689	16,777	22,174	407	552
Jun	14,237	22,803	506	811	18,540	25,504	627	849
Jul	16,605	25,666	597	919	21,016	29,980	721	951
Aug	17,315	26,861	628	965	20,553	28,939	618	811
Sep	14,846	22,603	502	761	18,816	25,403	837	1,017
Oct	13,049	20,951	519	758	16,548	22,648	555	734
Nov	13,595	21,451	523	727	16,546	22,907	473	637
Dec	12,817	20,193	464	660	15,950	21,999	535	678
Annual	14,904	22,486	435	690	18,562	25,688	499	697

Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. It is widely recognized that wholesale electricity markets will work better when a significant level of potential demand-side response is available in the market. 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.

A functional demand side of the electricity market does not mean that all customers curtail usage at specified levels of price. A fully functional demand side of the electricity market does mean that the default energy price for all customers will be the day-ahead or real-time hourly LMP. Customers will be able to choose to pay the day-ahead or real-time prices or to hedge their exposure to those prices by using an intermediary. A fully functional demand side of the electricity market does mean that all or most customers, or their designated intermediaries, will have the ability to see real-time prices in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use, based on real-time energy prices. In addition, customers will be able to specify the maximum price at which they wish to purchase power in the Day-Ahead Market. If these conditions are met, customers can decide for themselves the relationship between the price of power and the value of particular activities, from operating a production plant to running a commercial building to running a residential air conditioner. The true goal of demand-side programs is to ensure that customers can make informed decisions about energy consumption. Customers can and will make investments in demand-side management technologies based on their own evaluations of the tradeoffs among the price of power, the value of particular activities and the costs of those technologies.

A functional demand side of the wholesale energy market does not necessarily mean that prices will be lower than they otherwise would be. A functional demand side of these markets does mean, however, that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

A functional demand side of the wholesale electricity market would also send explicit price signals to suppliers, inducing more competitive behavior among suppliers and providing a market-based limit to suppliers' ability to exercise market power. If customers had the essential tools to respond to prices, then suppliers would have the incentive to deliver power on a cost-effective basis, consistent with their customers' evaluations.

The purpose of PJM's demand-side Economic Program is, or should be, to address a specific market failure, which is that many retail customers do not pay the market price or LMP. This represents a market failure because when customers do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the power used by customers is generated and sold in the wholesale power market.

Based on this purpose, the design goal of the Economic Program incentives should be to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale price. The real-time hourly LMP is the appropriate price signal as it reflects the incremental value of each MWh consumed.[53] The goal of the program should not be to encourage increased or decreased consumption, but to permit customers to face the market price and to make consumption decisions consistent with that price.

The PJM Economic Program is a wholesale program and its goal should be to ensure that the appropriate wholesale price signal is provided to customers but should not be to address retail rate issues. The design of retail incentives is a matter for state public utility commissions.

Retail customers pay retail rates including components that reflect the cost of generation (or power purchased from the grid), the cost of transmission and the cost of distribution. Under a rate design consistent with the purpose of the demand-side program, the hourly LMP would replace only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers. The LMP reflects the economic value of wholesale power and does not reflect the value of transmission or distribution services.

On March 15, 2002, PJM submitted filing amendments to the OATT and to the OA to establish a multiyear Economic Load-Response Program (the Economic Program).[54] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[55] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007.[56] On February 24, 2006, the FERC approved changes to the PJM Tariff to permit demand-side resources to provide ancillary services and to make the Economic Program permanent.[57,58] The same order permitted, for individual participants using the nonhourly metered option, an increase in the limit on the combined total MW in the Economic and Emergency Programs from 100 MW to 500 MW.

On November 20, 2007, the PJM Industrial Customer Coalition (PJMICC) filed a complaint with the FERC requesting continuation of Economic Load-Response subsidy payments that, under the existing PJM Tariff, would expire on December 31, 2007.[59] The Commission denied the complaint, stating that "Even without the subsidy payments, the Economic Program provides customers within PJM the incentive to reduce load based on the wholesale rates they confront."[60,61] On December 31, 2007, the Economic Program incentive payment provisions expired per the PJM OA.

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the retail incentive and regulatory structures faced by both load-serving entities (LSEs) and

53 This does not mean that every retail customer should be required to pay the real-time LMP, regardless of their risk preferences. However, it would provide the appropriate price signal if every retail customer were obligated to pay the real-time LMP as a default. That risk could be hedged via a contract with an intermediary.

54 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1326-000 (March 15, 2002).

55 99 FERC ¶ 61,227 (2002).

56 *PJM Interconnection, L.L.C.,* Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

57 114 FERC ¶ 61,201 (February 24, 2006).

58 Analysis of the role of demand-side resources in the Ancillary Service Markets can be found in the *2008 State of the Market Report,* Volume II, Section 6, "Ancillary Service Markets," at "Synchronized Reserve Market."

59 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 3.3.A (December 10, 2007).

60 121 FERC ¶ 61,315 (December 31, 2007) at ¶ 26.

61 For a discussion of subsidy payments under PJM's Economic Load-Response Program, see "MMU White Paper: PJM Demand Side Response Program" (December 4, 2007) <http://www.monitoringanalytics.com/reports/Reports/2007/20071204-dsr-whitepaper.pdf> (115 KB).

customers. The broader goal of the Economic Program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. Even as currently structured, however, and even with the reintroduction of the defined subsidies, if they exclude previously identified inappropriate components, the Economic Program represents a minimal and relatively efficient intervention into the market.[62]

On February 14, 2002, the PJM Members Committee approved a permanent Emergency Load-Response Program.[63] On March 1, 2002, PJM filed amendments to the OATT and to the OA to establish a permanent Emergency Load-Response Program (the Emergency Program).[64] By order dated April 30, 2002, the FERC approved the Emergency Program effective June 1, 2002. Like the Economic Program, a sunset date for it was set for December 1, 2004.[65] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[66] On February 24, 2006, the FERC approved changes to the PJM Tariff to make the Emergency Program permanent, including energy only and full emergency options.[67]

As a result of Reliability Pricing Model (RPM) implementation on June 1, 2007, the Emergency Program was modified to include an Emergency-Capacity Only option, to provide capacity credits to customers with Emergency-Full and Emergency-Capacity Only options, to make customers with the Emergency-Full option eligible for an Emergency-Energy payment for reductions during emergency events and to provide penalties for noncompliance during emergency events for customers with the Emergency-Full and Emergency-Capacity Only options.[68]

As part of the transition to RPM, effective June 1, 2007, the PJM active load management (ALM) program was changed to the load management (LM) program.[69] The LM program is comprised of two types of resources: ILR resources and demand resources (DR). Customers offering DR resources into an RPM Auction are paid the clearing price. Interruptible load for reliability (ILR) resources have to be certified at least three months prior to the delivery year and are paid the final zonal ILR price. An ILR resource can be registered under the Emergency-Capacity Only or Emergency-Full options of the Emergency and Economic Programs simultaneously. A DR resource can also be registered under the Emergency-Full option of the Emergency and Economic Programs simultaneously. However, a customer can participate in only one of the programs within an hour.

Customers with Emergency-Full and Emergency-Capacity Only options receive capacity credits on a daily basis. Customers with the Emergency-Full option are also eligible for an Emergency-Energy payment for reductions during emergency events. Customers with Emergency-Full and Emergency-Capacity Only options are obligated to respond during emergency events and face penalties for noncompliance.[70] The Emergency-Energy Only option is voluntary; customers who

62 One such inappropriate component was the payment of subsidies to customers who were already exposed to hourly LMP pricing.

63 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).

64 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).

65 99 FERC ¶ 61,139 (2002).

66 *PJM Interconnection, L.L.C.,* Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

67 114 FERC ¶ 61,201 (February 24, 2006).

68 For additional information on RPM provisions for customers in the Emergency Load-Response Program, refer to PJM's "Manual 18: "PJM Capacity Market."

69 An LM program continues to have three types of products: direct load control, firm service level or guaranteed load drop. Each of the products continues to have two notification periods: short-lead time and long-lead time.

70 "Emergency-Full customers that failed to provide a load reduction dispatched by PJM shall be assessed the ALM Deficiency Charge. The ALM Deficiency Charge shall equal the lesser of the Compliance Deficiency Value multiplied by the Daily Capacity Deficiency Rate multiplied by 365/10, or the Compliance Deficiency value multiplied two times the Annual Value of the Capacity Credit divided by a factor of 5." PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008), p. 70.

register for this option do not have to reduce their load during emergency events. Credits are paid to Emergency-Energy Only customers in the event of load reductions.

In addition to dispatchable demand resources, future RPM auctions may include energy efficiency resources. On December 12, 2008, PJM submitted amendments to the OATT to allow "investments in energy efficiency to offer into and clear RPM auctions like any other resource," beginning with the May 2009 Base Residual Auction for the 2012/2013 delivery year.[71] The filing proposes that an energy efficiency resource be eligible to enter and clear in RPM auctions and receive the applicable auction clearing price for four consecutive years, since for the first four years of implementation, the energy efficiency project will not be fully recognized in the load forecast and thus the customer's Peak Load Contribution (PLC) will not reflect the lower energy usage.

Emergency Program

The zonal distribution of DSR capability in the Emergency-Energy Only option of the Emergency Program is shown in Table 2-86. On June 9, 2008, the peak-load day for the year, there were no available resources in the Emergency-Energy Only option of the Emergency Program.[72] There was no activity under this option in calendar year 2008.

Table 2-86 shows the zonal distribution of DSR capability in the Emergency-Full option and in the Emergency-Capacity option of the Emergency Program on June 9, 2008. The PSEG Control Zone included 16 percent of all registered sites under the Emergency-Full option, while the AEP Control Zone included 27 percent of all registered MW. The ComEd Control Zone included 54 percent of all registered sites and 32 percent of all registered MW in the capacity option of the Emergency Program.

71 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER09-412-000 (December 12, 2008).

72 The number of registered sites and MW levels are measured as a one-day snapshot. The one-day snapshot is used because retail customers may change curtailment service providers (CSP) multiple times within a year and each such change would require a registration. When switching occurs, an annual total of registered sites would count the same sites and MW multiple times.

Table 2-86 Zonal capability in the Emergency Program (By option): June 9, 2008

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	63	16.6	7	8.6
AEP	0	0.0	137	512.5	54	698.5
AP	0	0.0	100	138.9	39	133.7
BGE	0	0.0	189	422.1	46	32.8
ComEd	0	0.0	69	95.6	877	820.9
DAY	0	0.0	23	8.4	8	50.0
DLCO	0	0.0	13	27.0	21	45.6
Dominion	0	0.0	47	63.2	29	46.0
DPL	0	0.0	59	5.5	74	81.1
JCPL	0	0.0	79	97.6	33	14.5
Met-Ed	0	0.0	70	150.7	24	40.8
PECO	0	0.0	143	60.2	154	216.9
PENELEC	0	0.0	38	50.5	35	30.0
Pepco	0	0.0	31	23.1	35	21.3
PPL	0	0.0	113	58.5	97	278.7
PSEG	0	0.0	228	167.4	63	19.9
RECO	0	0.0	3	1.0	21	1.1
Total	0	0.0	1,405	1,898.8	1,617	2,540.4

In 2008, there were no days with emergency activity. Table 2-87 shows zonal monthly capacity credits that were paid during the calendar year 2008 to ILR and DR resources. Credits from January to May are associated with participation in the 2007/2008 RPM delivery year, while credits from June to December are associated with participation in the 2008/2009 RPM delivery year. The increase in capacity credits after May is the result of a significant increase in both DR and ILR participation in RPM delivery year 2008/2009, as well as changes in RPM clearing prices.

Table 2-87 Zonal monthly capacity credits: January 1, 2008, through December 31, 2008

Zone	January	February	March	April	May	June	July	August	September	October	November	December
AECO	$37,969	$35,520	$37,969	$36,745	$37,969	$149,566	$154,551	$154,551	$149,566	$154,551	$149,566	$154,551
AEP	$152,155	$142,339	$152,155	$147,247	$152,155	$2,494,967	$2,578,133	$2,578,133	$2,494,967	$2,578,133	$2,494,967	$2,578,133
AP	$142,290	$133,110	$142,290	$137,700	$142,290	$935,647	$966,835	$966,835	$935,647	$966,835	$935,647	$966,835
BGE	$1,169,116	$1,093,689	$1,169,116	$1,131,403	$1,169,116	$2,789,189	$2,882,161	$2,882,161	$2,789,189	$2,882,161	$2,789,189	$2,882,161
ComEd	$618,740	$578,821	$618,740	$598,781	$618,740	$3,188,324	$3,294,602	$3,294,602	$3,188,324	$3,294,602	$3,188,324	$3,294,602
DAY	$2,530	$2,366	$2,530	$2,448	$2,530	$250,552	$258,904	$258,904	$250,552	$258,904	$250,552	$258,904
DLCO	$2,909	$2,721	$2,909	$2,815	$2,909	$250,151	$258,489	$258,489	$250,151	$258,489	$250,151	$258,489
DOM	$14,292	$13,370	$14,292	$13,831	$14,292	$286,760	$296,319	$296,319	$286,760	$296,319	$286,760	$296,319
DPL	$349,317	$326,780	$349,317	$338,049	$349,317	$644,091	$665,561	$665,561	$644,091	$665,561	$644,091	$665,561
JCPL	$319,163	$298,575	$319,163	$308,867	$319,163	$537,656	$554,279	$554,279	$537,656	$554,279	$537,656	$554,279
Met-Ed	$55,145	$51,588	$55,145	$53,366	$55,145	$659,743	$681,734	$681,734	$659,743	$681,734	$659,743	$681,734
PECO	$1,068,079	$999,170	$1,068,079	$1,033,625	$1,068,079	$1,331,207	$1,375,581	$1,375,581	$1,331,207	$1,375,581	$1,331,207	$1,375,581
PENELEC	$1,897	$1,775	$1,897	$1,836	$1,897	$274,105	$283,241	$283,241	$274,105	$283,241	$274,105	$283,241
Pepco	$133,068	$124,483	$133,068	$128,776	$133,068	$553,703	$572,160	$572,160	$553,703	$572,160	$553,703	$572,160
PPL	$320,247	$299,586	$320,247	$309,917	$320,247	$1,161,825	$1,200,552	$1,200,552	$1,161,825	$1,200,552	$1,161,825	$1,200,552
PSEG	$620,717	$580,671	$620,717	$600,694	$620,717	$891,281	$922,290	$922,290	$891,281	$922,290	$891,281	$922,290
RECO						$9,890	$10,219	$10,219	$9,890	$10,219	$9,890	$10,219
Total	$5,007,634	$4,684,564	$5,007,634	$4,846,100	$5,007,634	$16,408,657	$16,955,611	$16,955,611	$16,408,657	$16,955,611	$16,408,657	$16,955,611

Economic Program

On June 9th, 2008, there were 2,294.7 MW registered in the Economic Program compared to the 2,498.03 MW on August 8, 2007, an 8.1 percent decrease. (See Table 2-88.)

Table 2-88 Economic Program registration: Within 2002 to 2008

	Sites	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

Table 2-89 shows the zonal distribution of capability in the Economic Program on June 9, 2008. The PECO Control Zone includes 180 sites or 19 percent of sites and 9 percent of registered MW in the Economic Program. The BGE Control Zone includes 122 sites or 13 percent of sites and 26 percent of registered MW in the Economic Program. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. For example, the ComEd Control Zone showed a significant decrease in registered sites and MW when comparing peak days for 2008 and 2007.

On June 30, 2008, ComEd Control Zone registrations increased to 2,221 sites accounting for 835.9 registered MW, compared to the 83 sites and 137.5 MW registered on the 2008 peak load day.

Table 2-89 Zonal capability in the Economic Program: June 9, 2008

	Sites	MW
AECO	32	11.0
AEP	10	248.7
AP	25	186.2
BGE	122	601.6
ComEd	83	137.5
DAY	2	5.0
DLCO	44	181.2
Dominion	111	125.6
DPL	20	90.2
JCPL	48	115.4
Met-Ed	32	69.2
PECO	180	212.1
PENELEC	10	11.3
Pepco	15	16.3
PPL	74	203.2
PSEG	145	79.5
RECO	3	0.7
Total	956	2,294.7

The total MWh of load reduction and the associated payments under the Economic Program are shown in Table 2-90.[73] Load reduction levels decreased to 452,222 MWh in calendar year 2008.[74] Payments per MWh were $60 in 2008 compared to $74 in 2007. The Economic Program's actual load reduction per peak-day, registered MW decreased to 197.1 MWh for calendar year 2008, a decrease of 31 percent from 2007.[75] In the calendar year 2008, the maximum hourly load reduction attributable to the Economic Program was 493.6 MW on June 10.

73 The "Total MWh" and "Total Payments" for the Economic Program shown here are also subject to subsequent settlement adjustments in 2009.
74 The Economic Program payments and MWh presented in this report do not include all settlement adjustments for 2007 and 2008. The data are provided by PJM's DSR department; Economic Program payments and MWh reductions are based on the January, 2009, PJM billing information and are subject to adjustments.
75 The "Total MWh" and "Total Payments" for calendar year 2007 are different from those reported in the *2007 State of the Market Report,* as a result of adjusted settlements. The "Total MWh" increased by 105,403 MWh and the "Total Payments" increased by $3,860,339.

Table 2-90 Performance of PJM Economic Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$18,584,013	$72	234.8
2007	714,148	$49,033,576	$74	285.9
2008	452,222	$27,087,495	$60	197.1

While total MWh reductions are down by 261,926 or 36.7 percent, total payments are down by $21.9 million or 44.8 percent compared to 2007, meaning that there was a significant decrease in payments per MWh reduction. However, this is partially due to the sunset of the economic incentive program in November of 2007.[76] Table 2-91 shows total MWh reductions and payments less incentive payments.[77] Excluding the incentive portion, total payments fell $4.5 million, or 14.3 percent, from $31.6 million to $27.1 million, while payments per MWh of reduction increased from $44 per MWh in 2007 to $60 per MWh in 2008. Figure 2-20 shows monthly non-incentive economic program payments for 2007 and 2008. Economic Program credits have consistently declined since June of 2008. This is partially due to the CBL revisions effective June 12, 2008 and the newly implemented activity review process effective November 3, 2008. In addition, December credits are likely understated due to the lag associated with the submittal and processing of settlements.[78]

Table 2-91 Performance of PJM Economic Program participants without incentive payments

	Total MWh	Total Payments	$/MWh
2002	6,727	$801,119	$119
2003	19,518	$833,530	$43
2004	58,352	$1,917,202	$33
2005	157,421	$13,036,482	$83
2006	258,468	$10,213,828	$40
2007	714,148	$31,600,046	$44
2008	452,222	$27,087,495	$60

76 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 applicable retail rate (recoverable charges), was charged to all LSEs in the zone of the load reduction. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from calendar year 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

77 Settlement data for 2007 including reductions, credits and incentive payments data received from PJM DSR group February 2, 2009.

78 Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could account for a maximum lag of approximately 74 calendar days.

Figure 2-20 Economic Program Payments: Calendar years 2007 (without incentive payments) and 2008

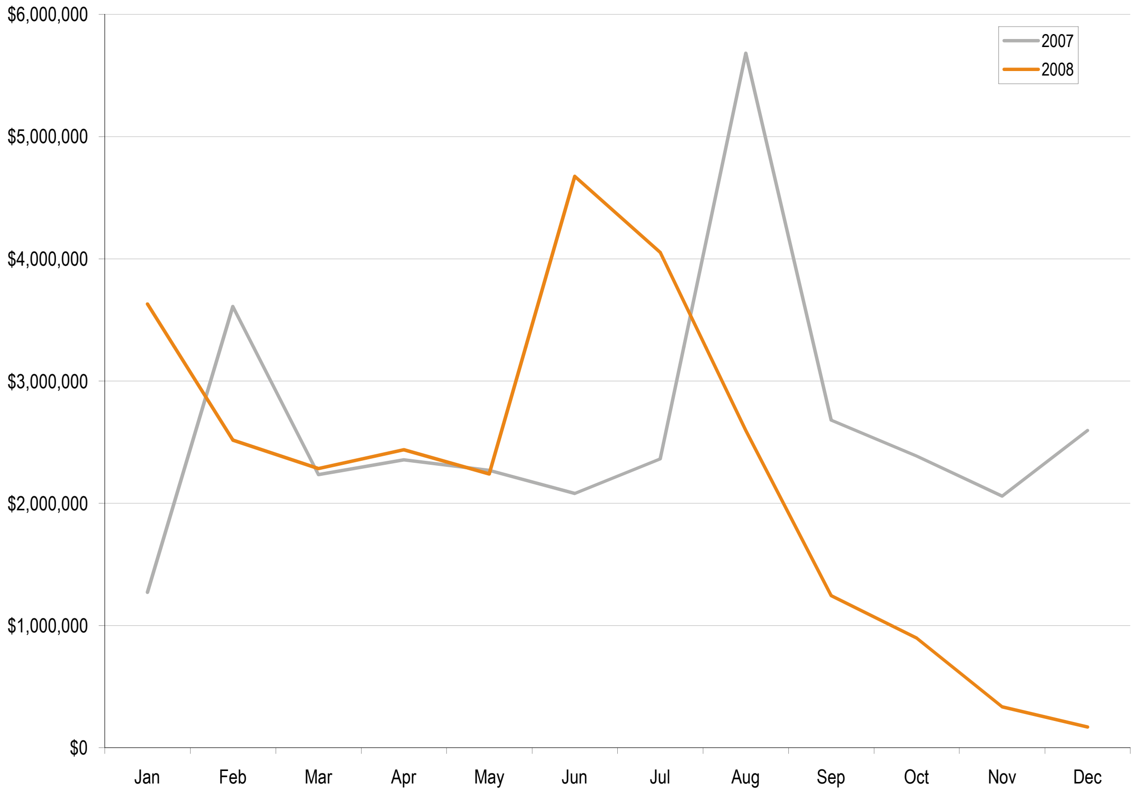


Table 2-92 shows 2008 performance in the Economic Program by control zone and participation type. The total number of curtailed hours for the Economic Program was 272,671 and the total payment amount was $27,087,495.[79] Overall, approximately 95 percent of the MWh reductions, 95 percent of payments and 88 percent of curtailed hours resulted from the real-time, self scheduled option of the Economic Program. Approximately 2 percent of the MWh reductions, 2 percent of payments and 1 percent of curtailed hours resulted from the day-ahead option.[80] Approximately 3 percent of the MWh reductions, 3 percent of the payments and 11 percent of the curtailed hours resulted from the dispatched in real time option of the program. (See Table 2-92.) PECO Control Zone accounted for $12.9 Million or 47.6 percent of all Economic Program credits, associated with 220,979 or 51.3 percent of total program reduction hours.

79 If two different retail customers curtail during the same hour in the same zone, it is counted as two curtailed hours.

80 On February 2, 2007, PJM proposed to the FERC that customers with day-ahead, LMP-based contracts be eliminated from participation in the day-ahead Economic Program. On June 15, 2007, the Commission issued an order, 119 FERC ¶ 61,280, rejecting PJM's proposed revision to its OATT.

Table 2-92 PJM Economic Program by zonal reduction: Calendar year 2008

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	190	$15,721	613	0	($118)	52	1,894	$78,852	1,267	2,083	$94,454	1,932
AEP	6,402	$256,595	484	4,252	$167,984	158	28	$3,834	11	10,681	$428,412	653
AP	18,215	$1,172,390	8,151	109	$4,590	242	193	$22,494	306	18,517	$1,199,473	8,699
BGE	4,911	$980,181	1,735	0	($12)	16	1	$30	56	4,912	$980,198	1,807
ComEd	23,987	$806,728	17,070	115	$4,198	43	6,261	$178,222	10,462	30,364	$989,148	27,575
DAY	2,073	$129,082	464				3	$163	6	2,076	$129,245	470
DLCO	35,330	$3,047,127	35,426	0	$83	10	455	$69,723	3,412	35,785	$3,116,933	38,848
Dominion	139	$18,312	675	0	$11	10	8	$54	266	148	$18,378	951
DPL	4,294	$114,225	974				13	$2,261	6	4,307	$116,487	980
JCPL	690	$107,259	548	0	($194)	70	181	$9,911	657	871	$116,976	1,275
Met-Ed	1,791	$97,486	1,237	28	$2,922	114	82	$7,072	403	1,902	$107,480	1,754
PECO	220,979	$12,673,642	142,308	4	$336	66	1,948	$227,551	9,379	222,931	$12,901,529	151,753
PENELEC	1,320	$45,450	771				94	$4,365	412	1,413	$49,815	1,183
Pepco	4,380	$240,208	790	0	($9)	10	476	$32,944	1,421	4,856	$273,143	2,221
PPL	104,908	$5,969,539	26,148	4,890	$427,588	1,400	636	$70,120	2,800	110,435	$6,467,246	30,348
PSEG	935	$98,644	2,015	0	($317)	134	1	$122	12	936	$98,448	2,161
RECO	5	$163	21	0	($34)	40				5	$129	61
Total	430,550	$25,772,752	239,430	9,399	$607,026	2,365	12,273	$707,717	30,876	452,222	$27,087,495	272,671
Max	220,979	$12,673,642	142,308	4,890	$427,588	1,400	6,261	$227,551	10,462	222,931	$12,901,529	151,753
Avg	25,326	$1,516,044	14,084	671	$43,359	169	767	$44,232	1,930	26,601	$1,593,382	16,039

Table 2-93 shows a frequency distribution of MWh reductions and credits at each hour for calendar year 2008. The period from hour ending 0800 EPT to 2300 EP accounts for 82.9 percent of MWh reductions and 88.9 percent of credits.

Table 2-93 Hourly frequency distribution of Economic Program MWh reductions and credits: Calendar year 2008

	MWh Reductions				Program Credits			
Hour	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
1	8,463	1.87%	8,463	1.87%	$293,368	1.08%	$293,368	1.08%
2	7,693	1.70%	16,155	3.57%	$259,091	0.96%	$552,460	2.04%
3	7,446	1.65%	23,601	5.22%	$217,326	0.80%	$769,786	2.84%
4	6,956	1.54%	30,558	6.76%	$196,816	0.73%	$966,602	3.57%
5	8,248	1.82%	38,806	8.58%	$229,140	0.85%	$1,195,742	4.41%
6	10,752	2.38%	49,558	10.96%	$366,991	1.35%	$1,562,733	5.77%
7	15,887	3.51%	65,445	14.47%	$1,073,345	3.96%	$2,636,078	9.73%
8	19,520	4.32%	84,965	18.79%	$1,188,912	4.39%	$3,824,990	14.12%
9	21,343	4.72%	106,308	23.51%	$1,029,934	3.80%	$4,854,923	17.92%
10	22,159	4.90%	128,468	28.41%	$1,130,251	4.17%	$5,985,175	22.10%
11	23,864	5.28%	152,332	33.69%	$1,402,151	5.18%	$7,387,325	27.27%
12	23,164	5.12%	175,496	38.81%	$1,337,262	4.94%	$8,724,587	32.21%
13	24,317	5.38%	199,813	44.18%	$1,481,200	5.47%	$10,205,787	37.68%
14	25,487	5.64%	225,300	49.82%	$1,659,776	6.13%	$11,865,563	43.80%
15	26,154	5.78%	251,454	55.60%	$1,811,141	6.69%	$13,676,704	50.49%
16	25,741	5.69%	277,195	61.30%	$1,997,403	7.37%	$15,674,107	57.86%
17	27,051	5.98%	304,246	67.28%	$2,293,169	8.47%	$17,967,276	66.33%
18	28,255	6.25%	332,501	73.53%	$2,422,544	8.94%	$20,389,820	75.27%
19	25,178	5.57%	357,679	79.09%	$1,623,219	5.99%	$22,013,039	81.27%
20	23,613	5.22%	381,292	84.32%	$1,465,585	5.41%	$23,478,624	86.68%
21	23,319	5.16%	404,611	89.47%	$1,594,456	5.89%	$25,073,080	92.56%
22	20,275	4.48%	424,887	93.96%	$1,119,104	4.13%	$26,192,184	96.69%
23	15,251	3.37%	440,138	97.33%	$520,459	1.92%	$26,712,642	98.62%
24	12,084	2.67%	452,222	100.00%	$374,853	1.38%	$27,087,495	100.00%

Table 2-94 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in price ranges of $15 per MWh. Reductions occurred primarily when zonal, load-weighted, average LMP was between $30 and $135 per MWh. Approximately 57.4 percent of MWh reductions and 27.7 percent of program credits are associated with hours when the applicable zonal LMP was less than or equal to $90.

Table 2-94 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2008

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
$0 to $15	10	0.00%	10	0.00%	$24,175	0.09%	$24,175	0.09%
$15 to $30	5,554	1.23%	5,564	1.23%	$25,101	0.09%	$49,277	0.18%
$30 to $45	37,723	8.34%	43,287	9.57%	$520,211	1.92%	$569,488	2.10%
$45 to $60	72,453	16.02%	115,740	25.59%	$1,556,315	5.75%	$2,125,803	7.85%
$60 to $75	77,818	17.21%	193,558	42.80%	$2,469,899	9.12%	$4,595,702	16.97%
$75 to $90	65,871	14.57%	259,430	57.37%	$2,915,585	10.76%	$7,511,286	27.73%
$90 to $105	47,571	10.52%	307,000	67.89%	$2,822,030	10.42%	$10,333,317	38.15%
$105 to $120	37,609	8.32%	344,609	76.20%	$2,707,346	9.99%	$13,040,662	48.14%
$120 to $135	29,150	6.45%	373,759	82.65%	$2,492,222	9.20%	$15,532,884	57.34%
$135 to $150	18,177	4.02%	391,936	86.67%	$1,780,902	6.57%	$17,313,787	63.92%
$150 to $165	15,437	3.41%	407,373	90.08%	$1,714,648	6.33%	$19,028,435	70.25%
$165 to $180	12,219	2.70%	419,593	92.78%	$1,547,170	5.71%	$20,575,605	75.96%
$180 to $195	6,807	1.51%	426,399	94.29%	$948,983	3.50%	$21,524,589	79.46%
$195 to $210	5,517	1.22%	431,917	95.51%	$863,014	3.19%	$22,387,602	82.65%
$210 to $225	4,193	0.93%	436,109	96.44%	$692,955	2.56%	$23,080,557	85.21%
$225 to $240	3,701	0.82%	439,810	97.26%	$682,771	2.52%	$23,763,328	87.73%
$240 to $255	2,089	0.46%	441,899	97.72%	$421,676	1.56%	$24,185,004	89.28%
$255 to $270	2,054	0.45%	443,953	98.17%	$440,102	1.62%	$24,625,106	90.91%
$270 to $285	1,564	0.35%	445,517	98.52%	$350,231	1.29%	$24,975,337	92.20%
$285 to $300	1,201	0.27%	446,718	98.78%	$291,846	1.08%	$25,267,183	93.28%
$300 to $315	714	0.16%	447,432	98.94%	$165,974	0.61%	$25,433,157	93.89%
$315 to $330	736	0.16%	448,169	99.10%	$199,831	0.74%	$25,632,988	94.63%
$330 to $345	492	0.11%	448,661	99.21%	$138,750	0.51%	$25,771,738	95.14%
$345 to $360	601	0.13%	449,261	99.35%	$190,984	0.71%	$25,962,722	95.85%
$360 to $375	131	0.03%	449,392	99.37%	$40,636	0.15%	$26,003,358	96.00%
$375 to $390	377	0.08%	449,768	99.46%	$118,611	0.44%	$26,121,969	96.44%
$390 to $405	178	0.04%	449,947	99.50%	$57,513	0.21%	$26,179,481	96.65%
$405 to $420	134	0.03%	450,081	99.53%	$32,948	0.12%	$26,212,429	96.77%
$420 to $435	344	0.08%	450,425	99.60%	$125,084	0.46%	$26,337,513	97.23%
$435 to $450	44	0.01%	450,469	99.61%	$15,083	0.06%	$26,352,596	97.29%
$450 to $465	331	0.07%	450,800	99.69%	$127,507	0.47%	$26,480,103	97.76%
$465 to $480	286	0.06%	451,086	99.75%	$109,688	0.40%	$26,589,791	98.16%
$480 to $495	95	0.02%	451,181	99.77%	$36,386	0.13%	$26,626,178	98.30%
$495 to $510	524	0.12%	451,704	99.89%	$222,398	0.82%	$26,848,575	99.12%
$510 to $525	23	0.01%	451,727	99.89%	$10,491	0.04%	$26,859,066	99.16%
$525 to $540	261	0.06%	451,989	99.95%	$118,563	0.44%	$26,977,629	99.59%
> $540	234	0.05%	452,222	100.00%	$109,867	0.41%	$27,087,495	100.00%

Active Load Management (ALM) and Load Management (LM)

Table 2-95 shows the available ALM MW for 2002 to 2006 and the available LM MW for 2007 and 2008.

Table 2-95 Available ALM MW and LM MW: Within 2002 to 2008

	2002	2003	2004	2005	2006	2007	2008
1-Jun	1,342	1,265	1,412	2,035	1,655	2,140	4,414
1-Jul	1,304	1,255	1,228	2,042	1,679	2,145	4,498
1-Aug	1,285	1,156	1,226	2,042	1,679	2,145	4,498
1-Sep	1,275	1,158	1,224	2,038	1,678	2,145	4,498

Price Impacts of Demand-Side Response

The price impact of demand-side response can be calculated in a number of ways. Prior to the *2006 State of the Market Report*, the MMU calculated the price impact using the aggregate summer PJM supply curve, as this represents the actual offers of PJM resources. However, the actual real-time prices in PJM reflect the fact that resources are not completely flexible and that the aggregate supply curve does not always reflect real-time limitations on the ability to dispatch available generation resources. Beginning with the *2006 State of the Market Report*, real-time hourly supply curves were developed for the period from June to September from actual PJM prices and corresponding loads, which represent the relationship between prices and loads in PJM for this time period. This method is straightforward and reproducible by any market analyst. The 2008 analysis showed that a reduction of 1 MW resulted in a price reduction of approximately $0.0025 per MW.

Issues and Program Changes

Customer Base Line (CBL) - History

Participants in the Economic Program are paid based upon the reductions in MWh usage that can be attributed to demand side actions and measures. Most participants in the Economic Program measure their reductions by comparing metered load against an estimate of what metered load would have been absent the reduction.[81] The general methodology is to create a base line usage level by calculating the average usage for a set of days that are intended to be representative of a retail customer's typical usage, including separate calculations for weekends/holidays. The extent to which the DSR Program can accurately quantify and compensate actual load reductions is dependent on the Program's ability to establish what a customer's metered load would have been absent any load reduction. This is a very difficult task and the methods used to date have been flawed, resulting in payments for reductions in usage that did not occur.

81 On-site generation meter data is the other method used to determine the load reduction, if used only for economic load reduction.

Since the beginning of the program, there have been significant issues with the approach to measuring demand-side response MW. An inaccurate or unrepresentative CBL can lead to payments when the customer has taken no action to respond to market prices. Substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The goal should be to treat the measurement of demand-side resources like the measurement of any other resource in the wholesale power market, including generation and load, that is paid by other participants or makes payments to other participants. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

Prior to recent process revisions, the electricity distribution company (EDC) or LSE was responsible for reviewing a customer's CBL data and could object to the calculations. When an EDC or LSE objected, customers had time to resubmit the data, which were also subject to review. From the beginning of the Economic Program, there were multiple settlement disputes in which an EDC or LSE did not approve CBL calculations and CSPs requested PJM involvement. These disputes were among the factors that led to the creation of the Customer Base Line Subcommittee (CBLS) in January 2007. The subcommittee's mission was to "Evaluate current methodology for PJM economic load response used to determine load reductions done through deliberate customer actions in response to expected day ahead and/or real time prices…[and] propose enhancements and/or changes that will improve the transparency and accuracy of the results which will also help to reduce the number of unanticipated settlement rejections."[82]

In December 2007, proposals to modify CBL business rules were presented to the PJM Market Implementation Committee with a focus on two major issues: the permissible period for selecting a comparable day and the number of days to be used for the CBL calculation; and the definition of a demand-side curtailment. The key criteria considered by the CBLS were empirical performance, simplicity, eliminating gaming/free-ridership, and overall cost to implement and administer.

On April 14, 2008, PJM filed with the FERC revisions to the Tariff and Operating Agreement to improve the Economic Program.[83] The filing included provisions to: (1) improve the method of establishing CBLs; (2) clarify that eligibility is limited to demand reductions in response to price; (3) establish objective criteria to assist with the identification of inappropriate market activity; and (4) provide PJM the authority to deny participation in the Program. Revisions were approved June 12, 2008.[84]

The revised, current weekday CBL methodology includes the highest four of most recent five weekdays, with a maximum lag on eligible days set at 45. Low usage days (load less than 75 percent of the average) and event days (days with curtailment events or demand reductions) are eliminated and replaced with prior days, unless there are not enough eligible days in the last 45 weekdays. Saturdays are considered separately, as are Sundays and holidays. The elimination of event days means that CBL measurements are not limited to the most recent five weekdays and can include weekdays from as far back as 45 days.

82 "Customer Baseline Committee Charter," February 27, 2007, <http://www.pjm.com/~/media/committees-groups/subcommittees/cbls/postings/20070223-final-charter.ashx> (22.7 KB).
83 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER08-824-000 (April 14, 2008).
84 123 FERC ¶ 61,257 (2008).

Prior to the revisions, the standard weekday CBL included the highest five weekdays of the most recent 10 weekdays, with no limit on how current CBL days must be. In addition, low usage days were defined as load less than 25 percent of average usage. Submitted settlement days were considered event days in CBL calculations even if they were eventually denied. Saturdays, Sundays and holidays were all considered “like days”.

The effect of the revisions approved June 12, 2008 was to provide for CBL calculations based on more recent and comparable data, which has made CBL calculations more representative of retail customers’ load absent any reduction activities. Additionally, the provision clarifying that participation is limited to reductions in response to real time prices and the establishment of PJM’s authority to deny participation were necessary program changes that are essential components of a rational verification process.

CBL - Issues

Even after the revisions, the CBL is still a simple, generic formula applied to nearly every customer’s usage and, as such, is not adequate to serve as the sole or primary basis for determining if an intentional load reduction took place. There are no mandatory CBL enhancements for customers with highly volatile load patterns.[85] If a customer normally has lower load on one particular weekday, that day will appear as a reduction eligible for payment under the current CBL methodology although no deliberate load reducing actions were taken in response to real time price signals. There are no adjustments for load levels that are a function of weather. In a mild week following a week of extreme temperatures and high load levels, a customer can submit settlements without taking any load reducing action and it will appear as a reduction eligible for payment because metered load is below CBL. There is no requirement in the DSR Program to periodically review CBLs to ensure that they are representative of customer load patterns. The only trigger for a CBL review in the program is a participation level greater than 70 percent in a rolling 30 weekday period.

The MMU has analyzed all settlement data submitted in the economic load response program from the period July 1 through November 1, 2008, to assess the revised CBL calculation.[86] While the revised CBL showed significant improvements in representing load patterns, the revised CBL methodology is still inadequate as a basis for defining and determining load reductions which are compensated under the PJM demand side programs. The tariff changes effective June 13, 2008, provide for a thirty day period to review activity in the Economic Load Response Program, after which, “the Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.”[87] PJM has not referred any participants or registrations to the MMU.

Determining the accuracy of a CBL is a difficult task. More data is required than the metered load associated with settlement and the CBL used to determine the reduction amount. However, that is the only data currently available to PJM at the time of settlement review. Complete historical data is required in order to determine whether the CBL is representative of normal load patterns. The

85 An alternative CBL can be developed if agreed upon by both the relevant LSE/EDC and the CSP.
86 Since behind the meter generation customers do not require a CBL, they were excluded from this analysis.
87 Section 3.3A.7

small number of hours of settlement data is not adequate. Prior to November 2008, many CSPs and customers routinely submitted settlements data in excess of what was needed to perform the settlement function. While this placed an administrative burden on PJM and the relevant LSEs/EDCs, one unintended result was that PJM had more complete load data for many customers.

Analysis of Settlements

The revised PJM settlement review process includes screens that will result in reduced submissions of excess settlement data.[88] While this is a positive change for the program, it limits the hourly metered load data available to PJM and thus limits the ability to assess whether a customer's CBL is representative. The MMU has evaluated CBL calculations for the period between the implementation of the CBL revisions and the implementation of the PJM Activity Review Process, when these data were still available.

Daily settlement submissions prior to November 2008 typically contained all 24 hours of data per day. In the period from July 1, 2008 through October 31, 2008, there were 12,067 daily settlements submitted, of which, 7,577, or 62.8 percent, included 24 hours of data. Of those 7,577 settlement days, 2,571 or 33.9 percent, showed a CBL greater than metered load for all 24 hours of the settlement day (Table 2-96). These settlements account for 41.9 percent of all economic payments for the period.

Table 2-96 Settlements showing consecutive 24 hour reductions as a percent of total settlements submitted for the period July 1, 2008 through October 31, 2008

	Settlement Days	Percent of Total Settlements	CSP Credits	Percent of Total Credit
24 consecutive hours CBL > Metered Load	2,571	21.3%	$3,165,418	41.9%
All other Settlements	9,496	78.7%	$4,381,443	58.1%
Total	12,067	100.0%	$7,546,861	100.0%

It is extremely implausible that any customer, let alone this proportion of customers, would take load reduction actions for 24 consecutive hours in response to real time price signals. It is also extremely implausible that an accurate CBL would result in metered load less than base line load for every hour of the day. It is more likely that the CBL is biased upward because it is based on usage from prior days with higher load. Under these circumstances, it is impossible to determine whether the customer took any load reducing actions, from the settlement data. It is the MMU's recommendation that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should initiate a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken prior to acceptance of such settlements.

The PJM Activity Review Process has significantly reduced the occurrence of 24 hour settlement submissions and therefore the frequency of 24 consecutive hours where the CBL is greater than metered load. However, there are still instances of requests for settlements passing the daily activity review screen while including 24 consecutive hours of reduction and these settlements are paid without any documentation of load reducing activities in response to real time price signals.

88 Specifically, the normal operations screen and the requirement that notification hours match settlement hours have resulted in a reduction of the submission of excess settlement data.

In the period November 1, 2008 through December 31, 2008, there were 3,027 settlement days submitted, of which, 638 or 21.1 percent contained all 24 hours of data. Of those 638 24-hour settlement days, 304, or 47.6 percent, show a CBL greater than metered load for all 24 hours. Of those 304 settlements, 151 were denied by PJM, while the remaining 153 were approved and account for $23,757 or 18.4 percent of Economic Program Credits for the period. While the frequency of consecutive 24 hour settlements has been significantly reduced, the proportion of those settlements that show a reduction for all 24 hours is higher at 47.6 than in the prior period when it was 33.9 percent.

In addition to submitting settlement claims for 24 consecutive hour periods, customers frequently submitted settlements for consecutive days. Prior to November 2008, many customers submitted settlement data for a large proportion of all available hours in a given month.

While the behavior is questionable, the resultant data permits a detailed analysis of customer behavior during this period. During the period July 1, 2008 through October 31, 2008, of the 223,830 settlement hours submitted, 184,627, or 82.5 percent, showed a CBL greater than the hourly metered load. Table 2-97 shows the number of actual settlement hours submitted as a percent of total hours in the period for the ten customers with the highest number of settlement hours from July 1, 2008 through October 31, 2008. Under the current CBL calculation, Customer A claimed to have reduced load for 75.5 percent of all available hours, peak and off peak, during the 123 day period. The top seven customers show CBL greater than metered load for more than 50 percent of the hours in the 123 day period. These settlements account for $1.1 Million or 14.9 percent of total CSP credits paid to load-reducing customers for the period.

The new PJM "normal operations" screen specifically targets this type of behavior and the frequency of consecutive daily settlement submission has dropped significantly since November 2008.

It is extremely implausible that any customer, let alone this proportion of customers, would take load reduction actions in response to real time price signals for more than 50 percent of the hours in a period covering approximately four months. It is also extremely implausible that an accurate CBL would result in metered load less than base line load for more than 50 percent of the hours in a period covering approximately four months. It is more likely that the CBL is biased upward because it is based on usage from prior days with higher load. The data also appear to show that even after the CBL revisions effective June 13, 2008, an upwardly biased CBL can result. Under these circumstances, it is impossible to determine whether the customer took any load reducing actions based only on the submitted settlement data.

Table 2-97 Ten highest submitting customers' data summary from the period July 1, 2008 through October 31, 2008

	Hours in Period	Hours Submitted	Percent of hours submitted	Hours CBL > metered load	Percent CBL> metered load of submitted	Percent CBL> metered load of all period hours	CSP Credits
Customer A	2,952	2,319	78.6%	2,228	96.1%	75.5%	$83,710
Customer B	2,952	2,230	75.5%	2,092	93.8%	70.9%	$739,166
Customer C	2,952	2,036	69.0%	1,886	92.6%	63.9%	$19,707
Customer D	2,952	2,030	68.8%	1,831	90.2%	62.0%	$101,495
Customer E	2,952	2,018	68.4%	1,804	89.4%	61.1%	$13,556
Customer F	2,952	1,954	66.2%	1,878	96.1%	63.6%	$8,983
Customer G	2,952	1,805	61.1%	1,611	89.3%	54.6%	$11,894
Customer H	2,952	1,796	60.8%	1,458	81.2%	49.4%	$5,660
Customer I	2,952	1,774	60.1%	1,630	91.9%	55.2%	$131,134
Customer J	2,952	1,773	60.1%	1,278	72.1%	43.3%	$8,133
Summary	29,520	19,735	66.9%	17,696	89.7%	59.9%	$1,123,440

Activity Review Process

Effective November 3, 2008, PJM began a new activity review process for settlements in the Economic Demand Side Response Program.[89] The activity review process includes a daily screen and a "normal operations" screen for identifying inappropriate behavior. In addition, the activity review process specifically defines the acceptable criteria for LSE/EDC denial of settlements. LSE/EDCs can no longer deny settlements based on whether the customer's CBL calculations reasonably represent load or on a determination that a load reduction action was not in response to price. While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, LSE/EDCs should be able to initiate PJM settlement reviews.

The daily screen provides that PJM will deny a daily settlement when any of the following criteria are met: (1) no advanced notification for settlements; (2) settlement hours do not match notification hours; (3) settlement is worth less than $5 in value; or (4) 75 percent or more of settlement hours show a retail generation and transmission rate higher than LMP.

The daily screen does indirectly address an issue with the CBL calculation, the ineligibility of "event days" for inclusion in CBL. When a high CBL results from high load days, a customer or CSP could submit settlements on daily basis to block lower load days from CBL eligibility, creating an upward bias in measured CBL. When a customer submits low value settlements for the purpose of blocking the inclusion of low load days from the CBL, the daily review process will deny them if they fail one of the four identified screens. But, PJM will not review daily settlements to assess responsiveness to price or accuracy of the CBL.

89 <http://www.pjm.com/Media/committees-groups/committees/drsc/20081031-item-04-dsr-activity-review-proc.pdf>

PJM's "normal operations" screen involves a review of all participation when a customer submits settlements for 70 percent (21 days) of available days in a rolling 30 weekday period. The review includes: (1) analysis of notifications and settlements; (2) review of registration contract; (3) required CSP submission of detailed description of load reduction activities; (4) written verification from end-use customer regarding DSR activity on specific days; and (5) optional on-site review. During this review, all new settlement requests will be denied pending the outcome of the review. Depending on the conclusion of the activity review, the registration may be terminated and the CSP may be referred to the FERC Office of Enforcement and/or the MMU, pursuant to the tariff.

Conclusions

Table 2-98 shows the number of customers and revenue by settlement days for the period July 1, 2008 through October 31, 2008. The Table shows the number of customers and the amount of revenue that would have been affected by the new normal operations screen for the period. The period included 123 days and the customers were grouped by their maximum number of settlement days for any 30 rolling weekday period. If the normal operations screen had been active for the period, 122 customers or 33.8 percent of active customers would have sufficient activity to warrant a review. These customers account for $6.9 Million or 91.4 percent of total program credits for the period.

Table 2-98 Distribution of customers and credits at various levels of settlement days in rolling 30 weekday basis

Settlement days in 30 rolling weekday period	Customers	Percent Customer	Percent Customer Cumulative	Credits	Percent Credit	Percent Credit Cumulative	Credit per Customer
1	22	6.4%	6.5%	$7,530	0.1%	0.1%	$342
2	20	5.8%	12.4%	$18,616	0.2%	0.3%	$931
3	8	2.3%	14.7%	$41,598	0.6%	0.9%	$5,200
4	6	1.7%	16.8%	$67,413	0.9%	1.8%	$11,236
5	12	3.5%	19.7%	$9,993	0.1%	1.9%	$833
6	6	1.7%	21.2%	$29,450	0.4%	2.3%	$4,908
7	5	1.5%	22.4%	$1,467	0.0%	2.3%	$293
8	6	1.7%	24.1%	$3,708	0.0%	2.4%	$618
9	6	1.7%	25.9%	$1,266	0.0%	2.4%	$211
10	8	2.3%	28.2%	$14,929	0.2%	2.6%	$1,866
11	11	3.2%	31.5%	$48,108	0.6%	3.2%	$4,373
12	11	3.2%	34.7%	$13,130	0.2%	3.4%	$1,194
13	12	3.5%	38.2%	$7,880	0.1%	3.5%	$657
14	17	5.0%	43.2%	$39,830	0.5%	4.0%	$2,343
15	13	3.8%	47.1%	$10,880	0.1%	4.2%	$837
16	12	3.5%	50.6%	$29,336	0.4%	4.6%	$2,445
17	12	3.5%	54.1%	$40,092	0.5%	5.1%	$3,341
18	16	4.7%	58.8%	$55,788	0.7%	5.8%	$3,487
19	8	2.3%	61.2%	$74,102	1.0%	6.8%	$9,263
20	10	2.9%	64.1%	$136,075	1.8%	8.6%	$13,607
21	7	2.0%	66.2%	$170,542	2.3%	10.9%	$24,363
22	8	2.3%	68.5%	$191,699	2.5%	13.4%	$23,962
23	9	2.6%	71.2%	$86,369	1.1%	14.6%	$9,597
24	19	5.5%	77.1%	$1,956,292	25.9%	40.5%	$102,963
25	17	5.0%	82.1%	$2,795,841	37.0%	77.5%	$164,461
26	17	5.0%	87.1%	$114,195	1.5%	79.1%	$6,717
27	14	4.1%	91.2%	$52,542	0.7%	79.8%	$3,753
28	11	3.2%	94.4%	$320,519	4.2%	84.0%	$29,138
29	4	1.2%	95.3%	$125,368	1.7%	85.7%	$31,342
30	16	4.7%	100.0%	$1,082,303	14.3%	100.0%	$67,644
Summary	343	100.0%		$7,546,861	100.0%		$22,003

The modifications to the CBL calculations and the new review process are significant improvements to the Economic Program, but the review process is not yet adequate to ensure that other customers are receiving the benefit of actual demand reductions when payments are made under the program. The new review process is not yet developed to the point that it can establish that load reductions are the result of identifiable load reducing actions taken in response to price. There is no explicit or implicit screening mechanism in place to verify that CBL calculations are representative of customer load.

The “normal operations” screen defines an explicit threshold for the proportion of available days submitted for settlement, at or above which the CSP and end use customer must substantiate their submitted demand reductions. It is not clear why it is appropriate to require documentation of load reduction activities above a threshold and require no documentation of load reduction activities below that threshold.

The definition of CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions.

The MMU recommends two ways to further improve the program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price.

- Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen.

- The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation. This would include the ongoing evaluation of whether CBL accurately represents customer load for each customer; analysis of settlements to determine responsiveness to price and; required submission of detailed description of load reduction activities on specific days.