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 PJM Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for 2007, 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 2007.

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 2007 summer period, the PJM Energy Market received an hourly average of 154,944 MW in net supply including hydroelectric generation.[3] The summer 2007 net supply was 615 MW lower than the summer 2006 net supply of 155,559. The decrease was comprised of 377 MWh of decreased hydroelectric power generation and 237 MWh of reduced offers from non-hydroelectric capacity.[4]

1 The MMU also compared 2007 market results to 2006 and certain other 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 *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

2 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

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 The *2006 State of the Market Report* reported a summer 2006 net capacity of 155,600 MW, which was rounded to the nearest 100 MW.

- Demand. The PJM system peak load in 2007 was 139,428 MW in the hour ended 1600 EPT on August 8, 2007, while the PJM peak load in 2006 was 144,644 in the hour ended 1700 on August 2, 2006.[5] The 2007 peak load was 5,216 MW, or 3.6 percent, lower than the 2006 peak load.

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

- Local Market Structure and Offer Capping. Noncompetitive local market structure is the trigger for offer capping. PJM implemented a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2006 and continued to apply the test in 2007. 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 fell from 0.4 percent in 2006 to 0.2 percent in 2007. In the Real-Time Energy Market offer-capped unit hours rose from 1.0 percent in 2006 to 1.1 percent in 2007.

- 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 2007. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to exempt owners when the market structure is competitive and to offer cap only pivotal owners when the market structure is noncompetitive.

  Specific geographic areas of PJM exhibited moderate to high levels of concentration when transmission constraints defined local markets. While PJM's local market power mitigation rules prevented the exercise of market power in these circumstances, the rules do not apply to units exempt from offer capping and therefore did not prevent the exercise of market power by a small number of such units.

- Characteristics of Marginal Units. The concentration of ownership of all marginal units in the Energy Market provides additional information about market structure. The higher the level of concentration of ownership of marginal units, the greater is the potential market power issue. In 2007, the top four companies accounted for 40 percent of the system's load-weighted, average locational marginal price (LMP).

  In 2007, coal-fired units accounted for 70 percent of marginal units and natural gas-fired units accounted for 24 percent of all marginal units.

5 For the purpose of Volume I and Volume II of the *2007 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 Conduct

- Price-Cost Markup. The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. For marginal units, the markup index is a measure of market power. A positive markup by marginal units will result in a difference between the observed market price and the competitive market price. The annual average markup index was 0.09 with a monthly average maximum of 0.22 in June and a monthly average minimum of 0.03 in January. 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.

Market Performance: Markup, Load and Locational Marginal Price

- Markup. The markup conduct of individual owners and units has an impact on market prices that is not measured by the price-cost markup index. 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, but such a full redispatch is practically impossible as 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 $5.86 per MWh, or 10 percent. The markup was $8.59 per MWh during peak hours and $2.91 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.

  A substantial portion of the markup, $0.57 per MWh or 10 percent occurred on high-load days during the summer of 2007. Markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power.

  The units that are exempt from offer capping for local market power accounted for $1.34 per MWh, or 23 percent, of the markup for all days. This is a disproportionate share, given that only 44 of 56 exempt units were marginal and that only eight exempt units of the 44 accounted for $1.15, or 86 percent, of this markup component of price. The average markup per exempt unit is about four times higher than for non-exempt units, and the average markup for the top eight exempt units is about 21 times higher than for non-exempt units.

- Load. On average, PJM real-time load increased in 2007 by 2.8 percent over 2006, rising from 79,471 MW to 81,681 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 2007 over 2006. The system simple average LMP was 16.9 percent higher in 2007 than in 2006, $57.58 per MWh versus $49.27 per MWh. The load-weighted LMP was 15.6 percent higher in 2007 than in 2006, $61.66 per MWh versus $53.35 per MWh. The fuel-cost-adjusted, load-weighted, average LMP was 18.1 percent higher in 2007 than in 2006, $63.00 per MWh compared to $53.35 per MWh. Fuel costs in 2007 contributed to downward pressure on LMP rather than upward pressure.

- 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 billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. For 2007, 95.9 percent of real-time load was supplied by bilateral contracts, 3.9 percent by spot market purchases and 0.2 percent by self-supply. Compared with 2006, reliance on bilateral contracts increased by 3.1 percentage points; reliance on spot supply decreased by 2.3 percentage points and reliance on self-supply decreased by 0.8 percentage points in 2007.

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 lead to 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. Total demand-side response resources available in PJM on August 8, 2007 (the peak day in 2007), were 2,145.30 capacity MW and 9.25 energy MW from the Emergency Load-Response Program and 2,498.03 energy 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 2007, 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 decreased by about 600 MW when comparing the summer of 2007 to the summer of 2006 while aggregate peak load decreased by 5,216 MW, modifying the general supply-demand balance from 2006 with a corresponding impact on-peak Energy Market prices. Overall load was higher than in

2006 and there were twice as many high-load days, with a corresponding impact on overall average prices. Market concentration levels remained moderate and average markups remained relatively low although markups increased. A small number of units exempt from offer capping accounted for a disproportionate share of the system markup. 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. The Energy Market was tighter than in 2006 and this explains, at least in part, higher prices and higher markups in 2007. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive.

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. The markup index is a direct measure of that relationship between price and marginal cost for individual unit offers. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to scarcity conditions. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for constraints not exempt from offer capping. 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.

The MMU recommends that the FERC terminate the exemption from offer capping currently applicable to generation resources used to relieve the western, central and eastern reactive limits in the Mid-Atlantic Area

Council (MAAC) control zones and the AP South Interface.[6] The MMU recommends that all constraints, including these interfaces, be subject to three pivotal supplier testing as specified in the PJM Amended and Restated Operating Agreement (OA). The exemptions for the identified interfaces are no longer necessary given PJM's dynamic implementation of the three pivotal supplier test based on actual market conditions in real time. It is not necessary to make an *ex ante* decision about the market structure associated with individual interface constraints that applies for an extended period. Prior to the implementation of the three pivotal supplier test, all units required to resolve a constraint were offer capped whenever the constraint was binding. For the identified exempt interfaces, this could have resulted in the inappropriate offer capping of a large number of units even when the relevant market was structurally competitive. That is no longer the case. Under the current PJM dynamic approach, offer capping is applied only as necessary and is applied on a nondiscriminatory basis for all units operating for all constraints.

The MMU also recommends that the FERC terminate the exemption from offer capping currently applicable to exempt units. PJM's offer-capping rules provide that specific units are exempt from offer capping, based on their date of construction. In a January 25, 2005, order, the FERC had found "that the exemption for post-1996 units from the offer capping rules is unjust and unreasonable under section 206 of the Federal Power Act and that the just and reasonable practice under section 206 is to terminate the exemption, with provisions to grandfather units for which construction commenced in reliance on the exemption."[7] The FERC noted, however, that grandfathered units would "still be subject to mitigation in the event that PJM or its market monitor concludes that these units exercise significant market power."[8] Exempt units exercised market power in 2006 and in 2007.

The rationale for grandfathering the specific 56 exempt units was that their owners might have relied on the exemption in deciding whether to invest. Given the substantial changes in PJM markets, including the introduction of the Reliability Pricing Model (RPM) construct and scarcity pricing, the rationale for grandfathering no longer holds. The combination of RPM and scarcity pricing has had a substantial impact on unit revenues, as demonstrated in the "Net Revenue" section of the *2007 State of the Market Report*. Rather than devise a special market power test for exempt units or go through a separate process for each such unit, it would be reasonable to remove the exemption on a going forward basis.

Energy Market results, including prices, for 2007 generally reflected supply-demand fundamentals. Higher nominal and load-weighted prices are consistent with a competitive outcome as the higher prices reflect higher overall demand and tighter supply-demand conditions. Fuel costs do not explain the increase in prices in 2007. If fuel costs for the year 2007 had been the same as for 2006, the 2007 load-weighted LMP would have been higher than it was. 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 are potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in 2007.

6 See PJM. "Amended and Restated Operating Agreement (OA)," Sections 6.4.1(d)(ii) and 6.4.1(e) (January 19, 2007).

7 110 FERC ¶ 61,053 (2005).

8 110 FERC ¶ 61,053 (2005).

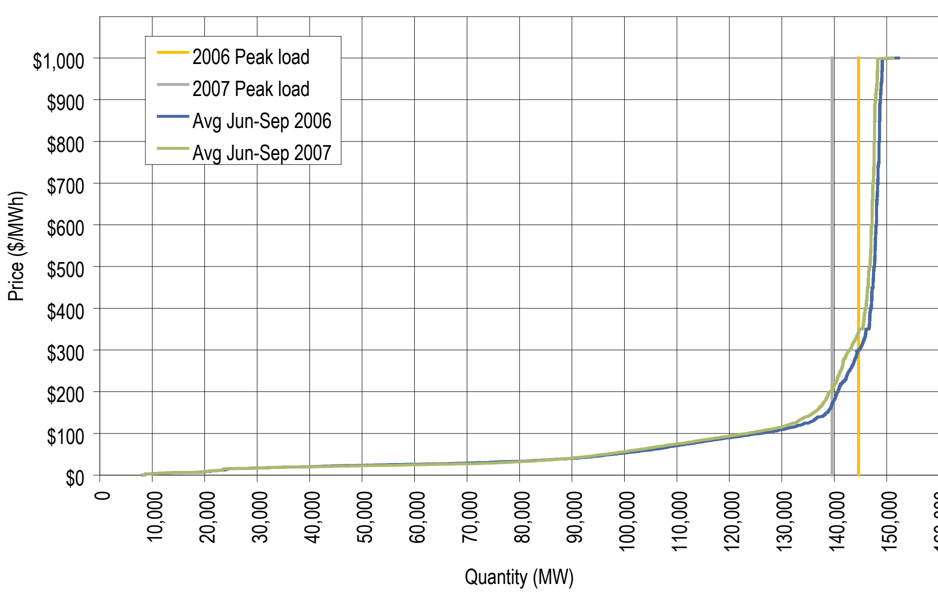
Market Structure

Supply

During the June to September 2007 summer period, the PJM Energy Market received an hourly average of 154,944 MW in net supply including hydroelectric generation. The summer 2007 net supply was 615 MW lower than the summer 2006 net supply of 155,559. The decrease was comprised of 377 MWh of decreased hydroelectric power generation and 237 MWh of reduced offers from non-hydroelectric capacity. During the summer of 2007, the peak demand was 5,216 MW, or 3.6 percent, lower than the 2006 peak and therefore intersected the supply curve at a lower price level. (See Figure 2-1.)

Offer prices on the 2007 supply curve are higher than on the 2006 supply curve from total supply levels of about 90,000 MW to 140,000 MW, corresponding to 2007 offers from about $41 per MWh to about $217 per MWh. During 2007, this range of offers consisted primarily of natural gas-fired steam, combined-cycle (CC) and efficient combustion turbine (CT) units. Approximately 78 percent of all gas-fired generation fell in this portion of the offer curve. The increase in the offer curve was in part the result of higher natural gas prices for summer 2007 compared to summer 2006. The average price of natural gas increased from $6.75 per MBtu for summer 2006 to $7.08 per MBtu for summer 2007, or 4.9 percent. Between about 145,000 MW and 150,000 MW the 2007 supply curve shifted left and parallel to the 2006 supply curve, meaning that incremental offers and MW are comparable between the two years. In aggregate, however, the 2007 supply curve shifted to the left by 895 MW. This shift was the result of a decrease of approximately 280 MW in offers of $500 per MWh to $1,000 per MWh and the 615 MW of decreased net supply. Total 2007 offers in the $500 to $1,000 per MWh range were approximately 7,380 MW.

Figure 2-1 Average PJM aggregate supply curves: Summers 2006 and 2007



During the 12 months ended September 30, 2007, 135 MW of generation entered service in the RTO.[9] The additions consisted of 128 MW in upgrades to existing generation and 7 MW in new generation, of which 5 MW were wind generation and 2 MW were diesel generation. Upgrades to existing facilities included 2 MW of combustion turbine generation, 5 MW of combined-cycle generation, 2 MW of coal-fired steam, 73 MW of gas/oil-fired steam, 13 MW of nuclear steam, 5 MW of wind generation, 25 MW of diesel generation and 3 MW of hydroelectric generation. After accounting for offsetting decreases of 356 MW from the derating of 66 MW of generation, 2 MW removed from RTO dispatch to behind the meter service and the retirement of 288 MW, the net decrease in capacity was 221 MW.

Of the 66 MW of derated generation, 22 MW were combustion turbine generation, 6 MW coal-fired steam, 10 MW gas/oil-fired steam, 4 MW nuclear steam, 8 MW wind generation and 16 MW diesel generation. The 2 MW of generation removed from PJM dispatch were diesel generation. Of the 288 MW of retirements, 280 MW were coal-fired steam, and 8 MW were diesel generation.

The net result of generation additions and subtractions, holding other factors constant, was a slight shift to the left of the PJM aggregate supply curve as a high proportion (97 percent) of retired generation was coal-fired steam generation. The shape of the aggregate supply curve changed only slightly since the net decrease of generation was less than 0.5 percent of the system supply.

Table 2-1 shows the PJM units that retired from October 1, 2006, to September 30, 2007.[10]

Table 2-1 Retired units: October 1, 2006, to September 30, 2007

Unit Name	Installed Capacity (MW)	Unit Type	Retire Date
PECO Delaware Diesel	3	Diesel	10/24/06
PPL Martins Creek 1	140	Steam	9/15/07
PPL Martins Creek 2	140	Steam	9/15/07
PPL Martins Creek D1-D2	5	Diesel	9/15/07
Total	288		

Demand

Table 2-2 shows the actual coincident summer peak loads for the years 1999 through 2007.[11] The 2007 actual summer peak load of 139,428 MW was 5,216 MW less than the 2006 summer peak load of 144,644.

9 This period was used to reflect capacity additions made through the summer.

10 Retired unit parameters obtained from PJM.

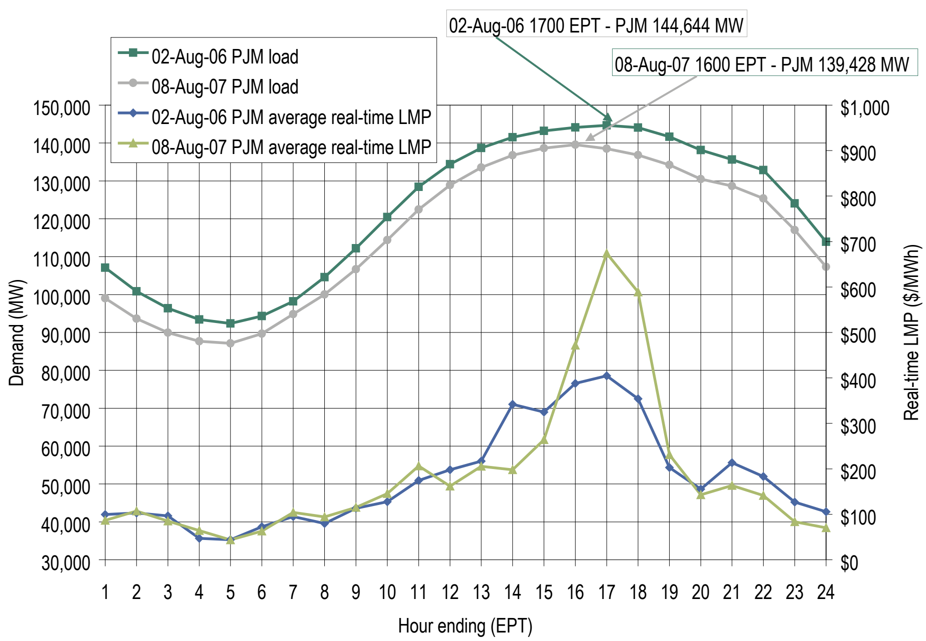
11 Peak loads shown are eMTR load. See the *2007 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of load.

Table 2-2 Actual PJM footprint summer peak loads: 1999 to 2007

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)

The hourly load and average PJM LMP for the 2007 and 2006 summer peak days are shown in Figure 2-2.

Figure 2-2 PJM summer peak-load comparison: Wednesday, August 2, 2006, and Wednesday, August 8, 2007



Market Concentration

During 2007, 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.[12] High concentration levels, particularly in the peaking segment,

12 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.

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 2007. 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. In addition, units that are exempt from PJM's offer-capping rules did exercise market power in some local markets in 2007.

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 price-cost markup index is one such test and direct examination of offer behavior by individual market participants is another. 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.

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.[13]

13 77 FERC ¶ 61,263 (2006), "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2007 was moderately concentrated. (See Table 2-3.) Based on the hourly Energy Market measure, average HHI was 1205 with a minimum of 879 and a maximum of 1545 in 2007. The highest hourly market share was 29 percent and the highest average market share for 2007 was 21 percent.

Table 2-3 PJM hourly Energy Market HHI: Calendar year 2007

	Hourly Market HHI
Average	1205
Minimum	879
Maximum	1545
Highest market share (One hour)	29%
Highest market share (All hours)	21%
# Hours	8760
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

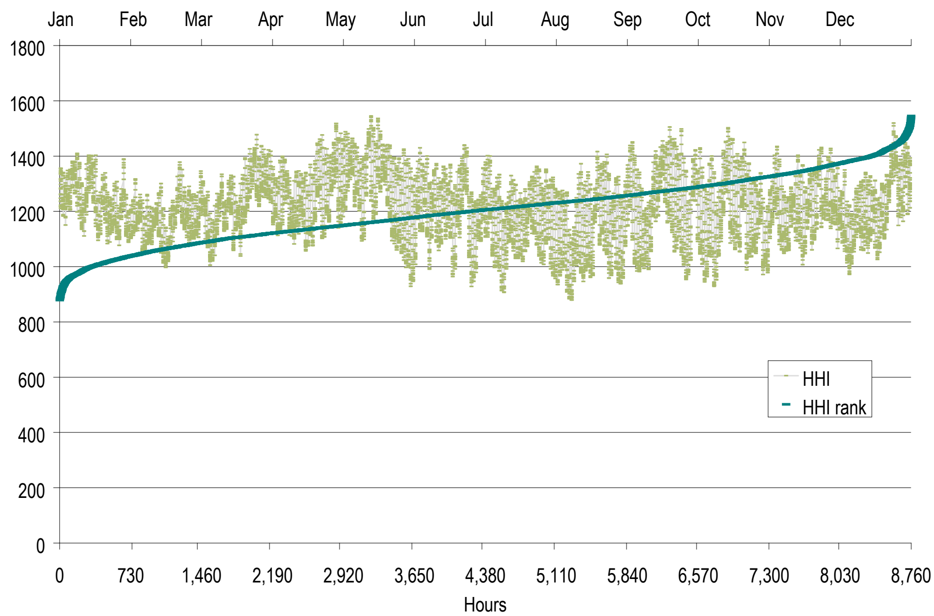
Table 2-4 includes 2007 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

Table 2-4 PJM hourly Energy Market HHI (By segment): Calendar year 2007

	Minimum	Average	Maximum
Base	1239	1392	1603
Intermediate	664	2158	6365
Peak	596	3746	10000

Figure 2-3 presents the 2007 hourly HHI values in chronological order and an HHI duration curve that shows 2007 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 4 percent of the hours while HHI values were in the moderately concentrated range in the remaining 96 percent of hours, with a maximum value of 1545, as shown in Table 2-3.

Figure 2-3 PJM hourly Energy Market HHI: Calendar year 2007



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.[14] 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

14 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2. (January 19, 2007).

the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempt certain units from offer capping based on the date of their construction. Such exempt units can, and do, exercise market power, at times, that would not be permitted if the units were not exempt.

Under existing rules, PJM exempts suppliers from offer capping 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.[15] 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.

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 2003 to 2007

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2003	1.1%	0.3%	0.4%	0.2%
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%

Table 2-6 presents data on the frequency with which units were offer capped in 2007. 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 2007.[16] For example, in 2007, 15 units were offer-capped for greater than, or equal to, 80 percent and less than 90 percent of their run hours and had 500 or more offer-capped run hours.

15 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

16 Offer-capped statistics in Table 2-6 are presented in a different format than previous years. The offer-capped percentage categories were also changed slightly to be consistent with the criteria for FMU eligibility. For example, the greater than 60 percent category was changed to greater than, or equal to, 60 percent which is consistent with the criteria for the Tier 1 adder (greater than, or equal to, 60 percent and less than 70 percent). Offer-capped statistics for prior years are shown in the revised format and with the revised percentage categories in the *2007 State of the Market Report,* Volume II, Appendix C, "Energy Market." Data quality improvements have caused values in these tables to vary slightly from previously published results.

Table 2-6 Offer-capped unit statistics: Calendar year 2007

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2007 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	1	3	2	6	0
80% and < 90%	15	3	0	14	13	6
75% and < 80%	0	0	0	0	2	4
70% and < 75%	0	0	2	0	1	3
60% and < 70%	0	0	0	1	3	24
50% and < 60%	1	0	0	0	0	21
25% and < 50%	0	0	0	0	0	51
10% and < 25%	0	0	0	3	12	37

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 47 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 2007 were offer capped for 10 percent or more of their run hours. Only 22 units (or about 2 percent of all units) had greater than, or equal to, 400 offer-capped run hours.

When compared to the 2006 offer-capped statistics, 25 percent of the categories show an increase in the number of units; 29 percent of the categories show no change and 46 percent of the categories show a decrease in the number of units.[17]

When compared to the 2005 offer-capped statistics, 31 percent of the categories show an increase in the number of units; 21 percent of the categories show no change and 48 percent of the categories show a decrease in the number of units.[18]

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 2007, the PSEG, AP, AEP, Met-Ed, JCPL, PENELEC, Dominion, DPL, AECO and DLCO 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 2007, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[19] The ComEd, BGE, PECO, PPL, RECO, Pepco and DAY control zones were not affected by constraints binding for 100 or more hours.

17 See the *2007 State of the Market Report*, Volume II, Appendix C, "Energy Market" Table C-22 for 2006 data.

18 See the *2007 State of the Market Report*, Volume II, Appendix C, "Energy Market" Table C-21 for 2005 data.

19 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

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 MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2007, through December 31, 2007.

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 exempt from 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 59 percent of the three pivotal supplier tests have one or more passing owners. In contrast, more local constraints like Gardners – Hunterstown in the Met-Ed Control Zone have only two suppliers and therefore are always structurally noncompetitive.

The fact that some non-exempt 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 always be exempt from offer capping for local market power. The same logic applies to currently exempt interface constraints. Even if no generation resources associated with any of the 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 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.

The MMU also recommends that three pivotal supplier testing be applied to all constraints in the clearing of the PJM Day-Ahead Energy Market. While PJM applies three pivotal supplier testing to the exempt interfaces in real time, the test is not applied consistently to the exempt interfaces in the Day-Ahead Market and the results of the test are not saved. As a result, it is not possible to analyze the market structure associated with the exempt interfaces in the Day-Ahead Market. The currently exempt interfaces accounted for \$167.6 million in day-ahead and -\$5.3 million in balancing congestion costs during 2007. The exempt interfaces were constrained for more hours in the Day-Ahead Market than in the Real-Time Market. During 2007, the exempt interfaces were constrained 2,703 hours in the Day-Ahead Market and 501 hours in the Real-Time Market.

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.[20] 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 2007, several regional transmission constraints occurred for more than 100 hours. The Kammer 765/500 kV transformer, along with four interface constraints (5004/5005,

20 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.

AP South, Bedington – Black Oak and West) all experienced more than 100 hours of congestion.[21] 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 are exempt from offer capping.

Table 2-7 includes information on the three pivotal supplier test results for the regional constraints.[22] For the three regional constraints that are not exempt, the percentage of tested intervals resulting in one or more owners passing ranged from 81 percent to 89 percent while 21 percent to 34 percent of the tests show one or more owners failing. For the AP South and West interfaces, which are exempt from offer capping, the percentage of tested intervals resulting in one or more owners passing ranged from 59 percent to 96 percent while 8 percent to 54 percent of the tests show one or more owners failing.

Table 2-7 Three pivotal supplier results summary for regional constraints: Calendar year 2007

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	646	576	89%	147	23%
	Off peak	274	228	83%	84	31%
AP South	Peak	276	176	64%	140	51%
	Off peak	157	92	59%	85	54%
Bedington - Black Oak	Peak	3,184	2,577	81%	1,071	34%
	Off peak	5,000	4,291	86%	1,405	28%
Kammer	Peak	1,487	1,327	89%	318	21%
	Off peak	2,518	2,114	84%	746	30%
West	Peak	718	689	96%	59	8%
	Off peak	656	618	94%	58	9%

Table 2-8 shows that, on average, during 2007 peak periods, the local markets created by the 5004/5005 Interface and the Kammer transformer had 21 owners with available supply and 20 owners with available supply, respectively. Of those owners, an average of 18 passed the test for the 5004/5005 Interface and an average of 17 passed the test for the Kammer transformer.[23] Bedington – Black Oak, on average, had 13 owners with available supply and 10 owners passed the test. For AP South, on average, 10 out of 17 owners passed the test during both on-peak and off-peak periods. For the West Interface, on average, 19 out of 20 owners passed the test during on-peak periods, and 17 out of 18 owners passed the test during off-peak periods.

21 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.

22 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.

23 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 2-8 Three pivotal supplier test details for regional constraints: Calendar year 2007

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	109	424	21	18	3
	Off peak	96	356	17	14	3
AP South	Peak	96	306	17	10	7
	Off peak	91	301	17	10	7
Bedington - Black Oak	Peak	62	234	13	10	3
	Off peak	63	240	11	9	2
Kammer	Peak	87	377	20	17	3
	Off peak	72	307	16	12	3
West	Peak	158	758	20	19	1
	Off peak	146	716	18	17	1

- East Interface and Central Interface. The remaining two exempt interfaces, the East and Central interface constraints occurred for fewer than 100 hours. The East Interface constraint occurred for five hours in 2007, while the Central Interface constraint occurred for 25 hours in 2007. Table 2-9 shows that the percentage of tested intervals resulting in one or more owners passing ranged from 56 percent to 97 percent while 14 percent to 100 percent of the tests showed one or more owners failing.

Table 2-9 Three pivotal supplier results summary for the East and Central interfaces: Calendar year 2007

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	28	24	86%	5	18%
	Off peak	29	28	97%	4	14%
East	Peak	9	5	56%	7	78%
	Off peak	1	0	0%	1	100%

Table 2-10 shows that, on average, the local market created by the East Interface had 15 owners during peak periods and seven passed the test. No owners passed the test during off-peak periods in 2007. The local market created by the Central Interface had 19 owners during off-peak periods and all passed the test. During on-peak periods, 17 of 19 passed the test for the Central Interface.

Table 2-10 Three pivotal supplier test details for the East and Central interfaces: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	87	445	19	17	3
	Off peak	168	914	19	19	1
East	Peak	363	1,009	15	7	8
	Off peak	187	694	12	0	12

- PSEG Control Zone Constraints. In 2007, five constraints in the PSEG Control Zone occurred for more than 100 hours. Table 2-11 and Table 2-12 show the results of the three pivotal supplier tests applied to these constraints. For four 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 – Roseland 230 kV line, which had more than four owners, on average. The Cedar Grove – Roseland 230 kV line 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 2-11 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2007

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
Branchburg - Flagtown	Peak	227	0	0%	227	100%
	Off peak	90	0	0%	90	100%
Branchburg - Readington	Peak	1,780	119	7%	1,760	99%
	Off peak	689	27	4%	683	99%
Brunswick - Edison	Peak	164	0	0%	164	100%
	Off peak	84	0	0%	84	100%
Cedar Grove - Roseland	Peak	148	26	18%	132	89%
	Off peak	210	28	13%	198	94%
Edison - Meadow Rd	Peak	270	0	0%	270	100%
	Off peak	34	0	0%	34	100%

Table 2-12 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Branchburg - Flagtown	Peak	23	21	3	0	3
	Off peak	26	4	3	0	3
Branchburg - Readington	Peak	27	64	4	0	3
	Off peak	23	68	4	0	4
Brunswick - Edison	Peak	11	84	1	0	1
	Off peak	10	76	1	0	1
Cedar Grove - Roseland	Peak	51	124	8	1	7
	Off peak	50	140	9	1	8
Edison - Meadow Rd	Peak	7	37	1	0	1
	Off peak	5	25	1	0	1

- **AP Control Zone Constraints.** In 2007, there were nine constraints that occurred for more than 100 hours in the AP Control Zone. Table 2-13 and Table 2-14 show the results of the three pivotal supplier tests applied to the constraints in the AP Control Zone. For six of the nine constraints, the average number of owners with available supply was six or less. 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. Three constraints, the Mount Storm – Pruntytown 500 kV line, the Sammis – Wylie Ridge 345 kV line and the Wylie Ridge transformer had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-13 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2007

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	2,017	4	0%	2,017	100%
	Off peak	548	0	0%	548	100%
Bedington - Nipetown	Peak	603	0	0%	603	100%
	Off peak	153	0	0%	153	100%
Elrama - Mitchell	Peak	975	209	21%	915	94%
	Off peak	1,930	397	21%	1,834	95%
Meadow Brook	Peak	1,974	0	0%	1,974	100%
	Off peak	213	0	0%	213	100%
Mitchell - Shepler Hill	Peak	344	0	0%	344	100%
	Off peak	325	0	0%	325	100%
Mitchell - Union Jct	Peak	265	0	0%	265	100%
	Off peak	113	0	0%	113	100%
Mount Storm - Pruntytown	Peak	168	132	79%	82	49%
	Off peak	481	410	85%	148	31%
Sammis - Wylie Ridge	Peak	39	18	46%	23	59%
	Off peak	394	285	72%	169	43%
Wylie Ridge	Peak	1,283	594	46%	759	59%
	Off peak	1,895	1,436	76%	712	38%

Table 2-14 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	27	4	2	0	2
	Off peak	29	6	2	0	2
Bedington - Nipetown	Peak	9	5	2	0	2
	Off peak	15	5	2	0	2
Elrama - Mitchell	Peak	27	75	6	1	5
	Off peak	28	50	5	1	5
Meadow Brook	Peak	34	1	2	0	2
	Off peak	20	1	2	0	2
Mitchell - Shepler Hill	Peak	8	10	2	0	2
	Off peak	10	7	2	0	2
Mitchell - Union Jct	Peak	13	47	2	0	2
	Off peak	13	29	2	0	2
Mount Storm - Pruntytown	Peak	127	368	13	9	4
	Off peak	104	379	11	9	2
Sammis - Wylie Ridge	Peak	42	73	15	8	7
	Off peak	43	110	16	10	5
Wylie Ridge	Peak	34	104	11	9	2
	Off peak	50	167	16	12	4

- AEP Control Zone Constraints. In 2007, there were five constraints that occurred for more than 100 hours in the AEP Control Zone. Table 2-15 and Table 2-16 show the results of the three pivotal supplier tests applied to the constraints in the AEP Control Zone. For three of the five 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 two constraints with the largest number of owners, on average. Two constraints, the Cloverdale – Lexington 500 kV line and the Cloverdale transformer, had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-15 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2007

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
Amos	Peak	529	0	0%	529	100%
	Off peak	89	0	0%	89	100%
Cloverdale	Peak	122	60	49%	82	67%
	Off peak	460	317	69%	227	49%
Cloverdale - Lexington	Peak	1,955	1,482	76%	874	45%
	Off peak	7,494	5,287	71%	3,819	51%
Darwin - Eugene	Peak	792	0	0%	792	100%
	Off peak	19	0	0%	19	100%
Mahans Lane - Tidd	Peak	340	0	0%	340	100%
	Off peak	474	0	0%	474	100%

Table 2-16 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Amos	Peak	33	19	2	0	2
	Off peak	24	19	2	0	2
Cloverdale	Peak	91	215	12	5	7
	Off peak	74	232	11	7	4
Cloverdale - Lexington	Peak	101	352	17	12	5
	Off peak	97	290	14	9	6
Darwin - Eugene	Peak	30	61	1	0	1
	Off peak	38	74	2	0	2
Mahans Lane - Tidd	Peak	10	16	1	0	1
	Off peak	20	12	1	0	1

- Met-Ed Control Zone Constraints. In 2007, there were four constraints that occurred for more than 100 hours in the Met-Ed Control Zone. Table 2-17 and Table 2-18 show the results of the three pivotal supplier tests applied to the constraints in the Met-Ed 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 one constraint with the largest number of owners, on average. The Brunner Island – Yorkana 230 kV line had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-17 Three pivotal supplier results summary for constraints located in the Met-Ed Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Brunner Island - Yorkana	Peak	531	277	52%	354	67%
	Off peak	230	105	46%	194	84%
Gardners - Hunterstown	Peak	375	1	0%	375	100%
	Off peak	58	0	0%	58	100%
Hunterstown	Peak	209	0	0%	209	100%
	Off peak	12	0	0%	12	100%
Jackson	Peak	290	0	0%	290	100%
	Off peak	5	0	0%	5	100%

Table 2-18 Three pivotal supplier test details for constraints located in the Met-Ed Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brunner Island - Yorkana	Peak	28	70	12	7	5
	Off peak	32	65	9	5	5
Gardners - Hunterstown	Peak	9	14	2	0	2
	Off peak	9	17	2	0	2
Hunterstown	Peak	10	27	2	0	2
	Off peak	8	41	2	0	2
Jackson	Peak	14	18	2	0	2
	Off peak	7	17	1	0	1

- JCPL Control Zone Constraints. In 2007, the Atlantic — Larrabee 230 kV line was the only constraint in the JCPL Control Zone to occur for more than 100 hours. Table 2-19 and Table 2-20 show the results of the three pivotal supplier tests applied to this constraint. The average number of owners with available supply was five on peak and three off peak. The three pivotal supplier test results reflect this, as 91 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 2-19 Three pivotal supplier results summary for constraints located in the JCPL Control Zone: Calendar year 2007

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	175	35	20%	160	91%
	Off peak	320	9	3%	320	100%

Table 2-20 Three pivotal supplier test details for constraints located in the JCPL Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Atlantic - Larrabee	Peak	32	25	5	1	5
	Off peak	35	36	3	0	3

- **PENELEC Control Zone Constraints.** In 2007, the East Towanda transformer and the East Towanda – South Troy line were the only constraints to occur for more than 100 hours in the PENELEC Control Zone. Table 2-21 and Table 2-22 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 one on peak and one off peak for the East Towanda – South Troy line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-21 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: Calendar year 2007

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	1,813	14	1%	1,806	100%
	Off peak	342	0	0%	342	100%
East Towanda - S.Troy	Peak	3	0	0%	3	100%
	Off peak	19	0	0%	19	100%

Table 2-22 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
East Towanda	Peak	12	4	3	0	3
	Off peak	6	4	3	0	3
East Towanda - S.Troy	Peak	4	17	1	0	1
	Off peak	7	3	1	0	1

- **Dominion Control Zone Constraints.** In 2007, there were three constraints in the Dominion Control Zone that occurred for more than 100 hours. Table 2-23 and Table 2-24 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 lines and six on peak and six off peak for the Clover transformer constraint. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-23 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2007

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	649	0	0%	649	100%
	Off peak	62	0	0%	62	100%
Clover	Peak	620	149	24%	601	97%
	Off peak	47	12	26%	47	100%
Halifax - Mount Laurel	Peak	584	46	8%	538	92%
	Off peak	384	54	14%	330	86%

Table 2-24 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2007

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	6	5	1	0	1
	Off peak	5	4	1	0	1
Clover	Peak	39	110	6	1	5
	Off peak	58	101	6	0	6
Halifax - Mount Laurel	Peak	11	2	1	0	1
	Off peak	11	2	1	0	1

- DPL Control Zone Constraints. In 2007, the Greenbush — Hallwood 69 kV line was the only constraint in the DPL Control Zone to occur for more than 100 hours. Table 2-25 and Table 2-26 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was one. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-25 Three pivotal supplier results summary for constraints located in the DPL Control Zone: Calendar year 2007

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
Greenbush - Hallwood	Peak	73	0	0%	73	100%
	Off peak	37	0	0%	37	100%

Table 2-26 Three pivotal supplier test details for constraints located in the DPL Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Greenbush - Hallwood	Peak	3	11	1	0	1
	Off peak	3	14	1	0	1

- AECO Control Zone Constraints. In 2007, there were two constraints in the AECO 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 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 2-27 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2007

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
Beckett - Paulsboro	Peak	885	0	0%	885	100%
	Off peak	277	0	0%	277	100%
Churchtown	Peak	203	0	0%	203	100%
	Off peak	177	0	0%	177	100%

Table 2-28 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beckett - Paulsboro	Peak	5	5	1	0	1
	Off peak	2	6	1	0	1
Churchtown	Peak	28	22	1	0	1
	Off peak	3	26	1	0	1

- DLCO Control Zone Constraints. In 2007, two constraints in the DLCO Control Zone experienced more than 100 hours of congestion. Table 2-29 and Table 2-30 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 – Evergreen line and two on peak and two off peak for the Collier – Elwyn 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 DLCO Control Zone: Calendar year 2007

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	263	0	0%	263	100%
	Off peak	21	0	0%	21	100%
Collier - Elwyn	Peak	415	1	0%	414	100%
	Off peak	296	0	0%	296	100%

Table 2-30 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cheswick - Evergreen	Peak	9	42	1	0	1
	Off peak	10	37	1	0	1
Collier - Elwyn	Peak	29	10	2	0	2
	Off peak	14	19	2	0	2

Characteristics of Marginal Units

Ownership of Marginal Units

Table 2-31 shows the contribution to PJM annual, load-weighted LMP by individual generation owner, utilizing generator sensitivity factors.[24] The contribution of each marginal unit to price at each load bus is calculated for the year and summed by the company that offers the unit into the Energy Market. The results show that, during calendar year 2007, the offers of one company contributed 13 percent of the annual load-weighted, average PJM system LMP and that the offers of the top four companies contributed 40 percent of the annual load-weighted, average PJM system LMP. There were 46 companies with individual contributions less than 4 percent and a combined contribution of 29 percent.

Table 2-31 Marginal unit contribution to PJM annual, load-weighted LMP (By company): Calendar year 2007

Company	Percent of Price
1	13%
2	10%
3	9%
4	8%
5	8%
6	7%
7	7%
8	5%
9	4%
Other (46 companies)	29%

24 See the *2007 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Marginal Unit Fuel

Table 2-32 shows the type of fuel used by marginal units.[25] In 2007, coal-fired units accounted for 70 percent of marginal units and natural gas-fired units accounted for 24 percent of all marginal units.[26]

Table 2-32 Type of fuel used (By marginal units): Calendar years 2005 to 2007

Fuel Type	2005	2006	2007
Coal	69%	70%	70%
Misc	1%	1%	2%
Natural gas	23%	25%	24%
Nuclear	0%	0%	0%
Petroleum	8%	5%	5%

Market Conduct

Unit Markup

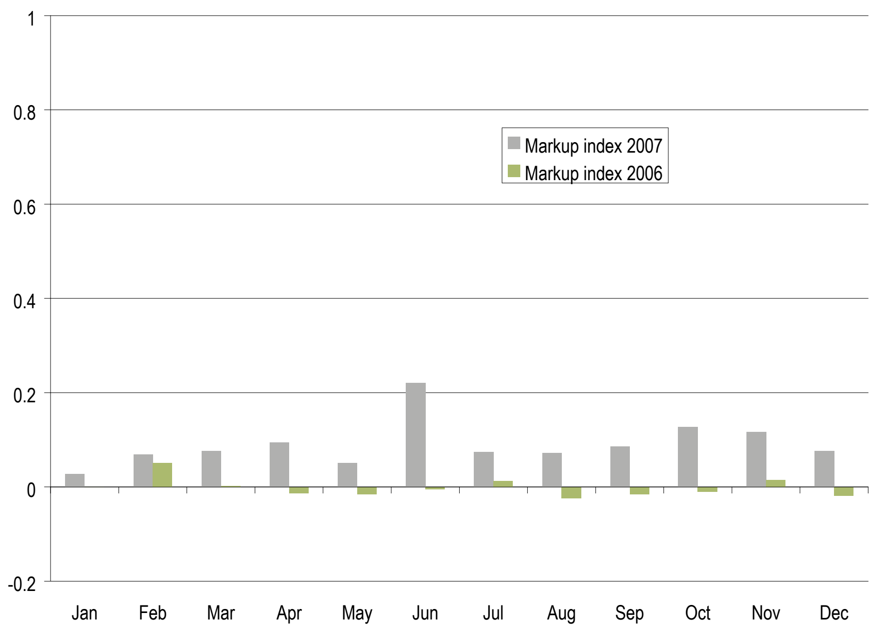
The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. For marginal units, the markup index is a measure of market power. For units not on the margin, the markup index is a measure of the intent to exercise market power or, in cases where the markup results in higher-priced units replacing lower-priced units in the dispatch, also a measure of market power. A positive markup by marginal units results in a difference between the observed market price and the competitive market price. The goal of the markup analysis is both to calculate the actual markups by marginal units (market conduct) and to estimate the impact of those markups on the difference between the observed market price and the competitive market price (market impact or market performance). The results must be interpreted carefully, however, because the impact is not based on a full redispatch of the system.

25 These percentages represent the proportion of the five-minute intervals that units of the specified fuel type were marginal compared to the total number of marginal unit intervals. For any interval with multiple marginal units, each unit is credited with an equal share of the interval. This methodology is the same one used to develop the marginal fuel type data posted to the PJM Web site at http://www.pjm.com/markets/jsp/marg-fuel-type-data.jsp. For example, a coal unit is on the margin during the first half of one hour. In the second half of the hour, two units are on the margin: a coal and a natural gas unit. Coal and gas are jointly marginal for the second half-hour. Coal is marginal for six five-minute intervals and jointly marginal for six five-minute intervals. Gas is jointly marginal for six five-minute intervals. Coal has a weight of 1.0 for the first six intervals and coal and gas each have a weight of 0.5 for the second six intervals. In this example, coal would be marginal for 75 percent of the hour and natural gas would be marginal for 25 percent of the hour.

26 The separate impact of each type of fuel on load-weighted, average LMP for 2007 is defined in the *2007 State of the Market Report*, Volume II, Section 2, “Energy Market, Part 1,” at “Components of Real-Time, Load-Weighted LMP,” Table 2-59, “Components of PJM annual, load-weighted, average LMP.”

Figure 2-4 shows the load-weighted, unit markup index. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[27] The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.[28] This index calculation method weights the impact of individual unit markups using sensitivity factors.[29] In 2007, the annual average markup index was 0.09 with a maximum of 0.22 in June and a minimum of 0.03 in January. The annual average markup index was higher than in 2006. In 2006, the annual average markup index was 0.00 with a maximum of 0.05 in February and a minimum of -0.02 in August.

Figure 2-4 Load-weighted unit markup index: Calendar years 2006 to 2007



27 A marginal unit's offer price does not always correspond to the LMP at the unit's bus. As a general matter the LMP at a bus is equal to the unit's offer. However in practice, actual, security-constrained dispatch can create conditions where the LMP at a marginal unit bus does not correspond to the unit's offer. The unit offer price and associated cost are used when calculating measures of participant behavior or conduct, like markup.

28 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

29 In prior state of the market reports, the impact of each marginal unit on load and LMP was based on an estimate when there were multiple marginal units. Sensitivity factors define the impact of each marginal unit on LMP at every bus on the system. See the *2007 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors." See also "PJM 101: The Basics" (September 14, 2006) <http://www.pjm.com/services/training/downloads/pjm101part1.pdf> (5.7 MB), p. 107.

Unit Markup Characteristics

In order to contribute to a more complete description of markup behavior, this section includes information on markup by unit and fuel type and by offer price category.

Table 2-33 shows the annual average unit markup for marginal units, by unit type and primary fuel.

Table 2-33 Average marginal unit markup index (By primary fuel and unit type): Calendar year 2007

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	0.03	$5.44
Heavy oil	Steam	0.01	$1.93
Hydroelectric	Hydroelectric	0.00	$0.00
Light oil	CT	0.10	$39.96
Light oil	Diesel	0.07	$16.48
Misc	Misc	0.01	($1.26)
Natural gas	CC	0.08	$22.37
Natural gas	CT	0.04	$7.06
Natural gas	Diesel	0.04	$9.72
Natural gas	Steam	0.02	$7.37
Nuclear	Steam	(0.00)	$0.23

Table 2-34 shows the average markup of marginal units, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-34 Average marginal unit markup index (By price category): Calendar year 2007

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($2.36)
$25 to $50	(0.02)	($1.43)
$50 to $75	0.06	$0.01
$75 to $100	0.13	$9.50
$100 to $125	0.17	$18.33
$125 to $150	0.19	$25.88
> $150	0.14	$51.01

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. These measures include the impact of markup on system prices and the impact of markup on zonal prices. In addition, the impact of the markup of specific subsets of units on system and zonal prices is analyzed, including units exempt from offer capping, units on high-load days and frequently mitigated units.

In each case, 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.[30] The 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 explicit measures of the impact of marginal unit markups on LMP. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, but such a full redispatch is practically impossible as 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.

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

Markup Component of System Price

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

Table 2-35 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2007, $5.86 per MWh of the PJM load-weighted average LMP was attributable to markup. In 2007, the markup component of LMP was $2.91 per MWh off peak and $8.59 per MWh on peak. Of the markup component, $0.57 per MWh, or 10 percent, occurred on high-load days. Markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power.[31]

Table 2-35 Monthly markup components of load-weighted LMP: Calendar year 2007

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$1.85	$3.22	$0.36
Feb	$6.54	$10.18	$2.82
Mar	$5.93	$8.20	$3.53
Apr	$6.75	$9.78	$3.55
May	$3.39	$5.85	$0.54
Jun	$3.50	$5.51	$1.18
Jul	$4.70	$6.71	$2.55
Aug	$5.37	$7.04	$3.23
Sep	$5.79	$9.33	$2.43
Oct	$10.09	$14.06	$5.18
Nov	$10.44	$15.23	$5.47
Dec	$6.95	$9.92	$4.30
2007	$5.86	$8.59	$2.91

Markup Component of Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-36. The smallest zonal all hours' markup component was in the DLCO Control Zone, $3.95 per MWh, while the highest all hours' zonal markup component was in the RECO Control Zone, $7.33 per MWh. On peak, the smallest zonal markup was in the DLCO Control Zone, $6.56 per MWh, while the highest markup was in the RECO Control Zone, $10.18 per MWh. Off peak, the smallest zonal markup was in the DLCO Control Zone, $1.16 per MWh, while the highest markup was in the RECO Control Zone, $3.94 per MWh. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The price impact of markup must be

31 For a definition and list of high-load days, see the *2007 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," at "High-Load Events, Scarcity and Scarcity Pricing Events." For the analysis of components of LMP, 25 days are included when high-load days are referenced. These days are June 1, 26 and 27; July 9, 10, 18, 26, 27, 30 and 31; and August 1 to 3, 6 to 10, 13, 15 to 17, 24, 28 and 29, 2007. The three scarcity hours on August 8 are not included.

interpreted carefully. 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.

Table 2-36 Average zonal markup component: Calendar year 2007

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$6.43	$9.22	$3.46
AEP	$4.57	$7.03	$2.02
AP	$4.81	$6.86	$2.65
BGE	$6.93	$9.89	$3.80
ComEd	$4.73	$7.23	$1.96
DAY	$4.86	$7.42	$2.02
DLCO	$3.95	$6.56	$1.16
Dominion	$6.61	$9.56	$3.47
DPL	$6.69	$9.69	$3.51
JCPL	$6.75	$9.57	$3.57
Met-Ed	$6.27	$8.88	$3.40
PECO	$6.74	$9.74	$3.50
PENELEC	$5.56	$8.22	$2.69
Pepco	$6.83	$9.62	$3.78
PPL	$6.41	$9.15	$3.43
PSEG	$7.02	$10.07	$3.62
RECO	$7.33	$10.18	$3.94

Markup by System Price Levels

Table 2-37 shows the average markup component of observed price when the PJM system LMP was in the identified price range.

Table 2-37 Average markup (By price category): Calendar year 2007

	Average Markup Component	Frequency
Below $20	($1.83)	3%
$20 to $39.99	($0.56)	35%
$40 to $59.99	$3.70	23%
$60 to $79.99	$7.88	18%
$80 to $99.99	$12.19	12%
$100 to $119.99	$15.24	5%
$120 to $139.99	$15.50	2%
$140 to $159.99	$21.57	1%
Above $160	$38.09	1%

Exempt Unit Markup

PJM's offer-capping rules provide that specific units are exempt from offer capping, based on their date of construction. During 2005, two orders issued by the FERC modified the rules governing exemptions from the offer-capping rules. In the January 25, 2005, order, the FERC found "that the exemption for post-1996 units from the offer-capping rules is unjust and unreasonable under section 206 of the Federal Power Act and that the just and reasonable practice under section 206 is to terminate the exemption, with provisions to grandfather units for which construction commenced in reliance on the exemption."[32] The FERC noted, however, that grandfathered units would "still be subject to mitigation in the event that PJM or its market monitor concludes that these units exercise significant market power."[33] In the July 5, 2005, order, the FERC modified the dates governing unit exemptions by zone.[34] The effect of these orders was to reduce the number of units exempt from local market power mitigation rules from 215 to 56 as of the end of 2005 and that number did not change in 2006 or in 2007.

Table 2-38 compares the markup components of price of exempt and non-exempt units in 2007. Of the 56 generators that are exempt from offer capping, 44 were marginal in 2007. The 44 marginal exempt units accounted for $1.34, 23 percent, of the total markup component of LMP in 2007. Of the 44 units, the top eight exempt units contributed 86 percent of the total markup component of exempt units, or 20 percent of the total markup component for all of PJM. The average markup per exempt unit is about four times higher than for non-exempt units, and the average markup for the top eight exempt units is about 21 times higher than for non-exempt units. This analysis does not address whether these units would have been offer

32 110 FERC ¶ 61,053 (2005).
33 110 FERC ¶ 61,053 (2005).
34 112 FERC ¶ 61,031 (2005).

capped had they not been exempt and therefore does not address how much the contribution to LMP would have changed if the exemption had been removed. 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.

Table 2-38 Comparison of exempt and non-exempt markup component: Calendar year 2007

	Units Marginal	Markup Component
Non-exempt units	684	$4.52
Exempt units	44	$1.34

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.[35] 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.[36] The settlement agreement revised the definition of FMUs to provide for a set of graduated adders associated with increasing levels of offer capping.[37] 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.[38] 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 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.[39]

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

35 110 FERC ¶ 61,053 (2005).

36 114 FERC ¶ 61,076 (2006).

37 *PJM Interconnection, L.L.C.*, Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

38 OA, Fifth Revised Sheet No. 131B (Effective July 3, 2007).

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

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 2-39 shows the number of FMUs and AUs in each month of 2007. For example, in December 2007, there were 15 FMUs and AUs in Tier 1, 13 FMUs and AUs in Tier 2, and 73 FMUs and AUs in Tier 3.

Table 2-39 Frequently mitigated units and associated units (By month): Calendar year 2007

	FMUs and AUs			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	22	56	53	131
February	18	49	63	130
March	24	46	58	128
April	16	52	58	126
May	14	62	52	128
June	16	66	46	128
July	15	45	68	128
August	25	30	76	131
September	23	21	81	125
October	13	22	84	119
November	22	13	76	111
December	15	13	73	101

Table 2-40 shows the number of months FMUs and AUS were eligible for any adder (Tier 1, Tier 2 or Tier 3) during 2007. Of the 142 units eligible in at least one month during 2007, 121 units (85 percent) were FMUs or AUs for more than eight months. Approximately two-thirds of the units (93 units or 65 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.

Table 2-40 Frequently mitigated units and associated units total months eligible: Calendar year 2007

Months Adder-Eligible	FMU & AU Count
1	5
2	2
3	1
4	5
5	0
6	1
7	2
8	5
9	10
10	10
11	8
12	93
Total	142

Table 2-41 shows the impact of the offer-cap adders for frequently mitigated units and associated units on LMP in each zone.[40] The impact is calculated, using sensitivity factors, by comparing the actual LMP to what the LMP would have been in the absence of the FMU and AU adders. The zone reflects where the price impact occurs, not the location of the FMUs or AUs. The additional energy cost is the affected load multiplied by the locational price impacts. The MMU calculates explicit measures of the impact of the FMU and AU adders on LMP. The price impact must be interpreted carefully. The price impact includes the maximum impact of the FMU and AU adders.

40 The PJM total includes load at certain buses which are dynamically dispatched by PJM, but which are not part of a PJM control zone. As a result, the PJM total is not equal to the sum of zonal totals in this analysis.

Table 2-41 Cost impact of FMUs and AUs (By zone): Calendar year 2007

	FMU and AU Marginal Energy Impacts (Millions)	Total Energy Cost (Millions)	Percent	LMP Impact
AECO	$21.88	$837.91	2.61%	$1.87
AEP	$35.83	$7,371.00	0.49%	$0.24
AP	$36.99	$2,986.31	1.24%	$0.76
BGE	$41.15	$2,659.35	1.55%	$1.18
ComEd	$23.93	$5,235.91	0.46%	$0.23
DAY	$4.48	$969.72	0.46%	$0.23
DLCO	$1.77	$721.39	0.25%	$0.12
DPL	$15.30	$1,366.27	1.12%	$0.78
Dominion	$80.60	$6,996.28	1.15%	$0.84
JCPL	$21.30	$1,811.21	1.18%	$0.85
Met-Ed	$16.52	$1,093.38	1.51%	$1.05
PECO	$27.28	$2,871.28	0.95%	$0.64
PENELEC	$10.09	$1,059.66	0.95%	$0.55
Pepco	$38.81	$2,509.29	1.55%	$1.19
PPL	$30.38	$2,935.57	1.03%	$0.68
PSEG	$32.18	$3,404.72	0.95%	$0.67
RECO	$0.92	$119.45	0.77%	$0.54
PJM	$433.41	$44,120.82	0.98%	$0.61

Markup Component of Price on High-Load Days

Scarcity exists when the total demand for power approaches the generating capability of the system. Scarcity pricing means that market prices reflect the fact that the system is close to its available capacity and that competitive prices may exceed accounting, short-run marginal costs. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[41] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power.[42] Under the current PJM rules, administrative scarcity pricing, based on the scarcity pricing provisions in the Tariff, results when PJM takes identified emergency actions and is based on the highest offer of an operating unit.[43]

41 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part I," at Figure 2-1,"Average PJM aggregate supply curves: Summers 2006 and 2007."

42 For a definition of high-load days, see the *2007 State of the Market Report,* Volume II, Section 3, "Energy Market, Part 2," at "2007 High-Load Events, Scarcity and Scarcity Pricing Events."

43 See the *2007 State of the Market Report,* Volume II, Section 3, "Energy Market, Part 2," at "2007 High-Load Events, Scarcity and Scarcity Pricing Events." This administrative scarcity pricing, as defined by PJM rules, is one type of the broader category of scarcity pricing.

The markup component of price is higher during peak-demand periods. Figure 2-5 shows the hourly load-weighted, average markup component of price for the summer of 2007. [44]

Figure 2-5 Average hourly markup and load: Summer 2007

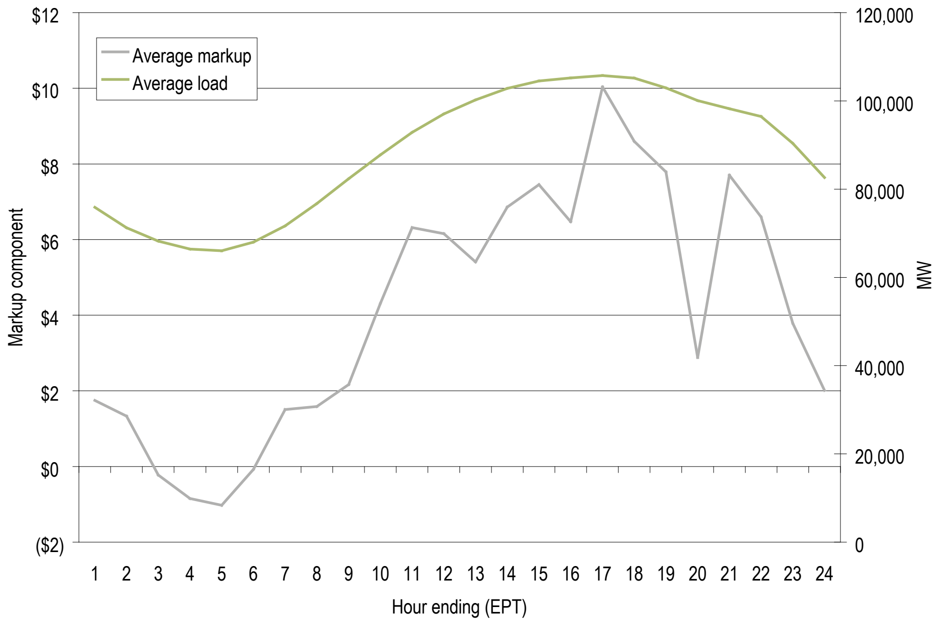


Table 2-42 shows that $0.57 per MWh, or 10 percent, of the total markup component of price occurred on high-load days. In addition, for non-exempt units, about 7 percent of the total markup component of price occurs on high-load days. For exempt units, about 19 percent of the total markup component of price occurs on high-load days.

Table 2-42 Markup contribution of exempt and non-exempt units: Calendar year 2007

	Exempt Markup Component	Non-Exempt Markup Component	Total
High-load days	$0.25	$0.32	$0.57
Balance of year	$1.09	$4.20	$5.29
Total	$1.34	$4.52	$5.86

44 Summer is defined as from June 1, 2007, to September 1, 2007.

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 and the Day-Ahead Energy Market, which started on January 1, 1998, and June 1, 2000, respectively.

Load

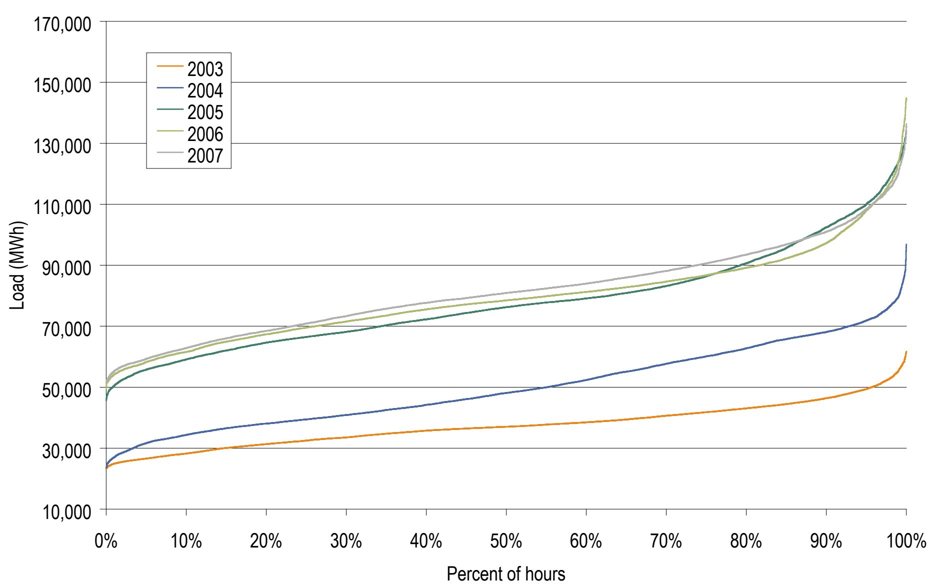
Real-Time Load

PJM real-time load is the total hourly accounting load in real time.[45]

PJM Real-Time Load Duration

Figure 2-6 shows PJM real-time load duration curves from 2003 to 2007. A load duration curve shows the percent of hours that load was at, or below, a given level for the year.

Figure 2-6 PJM real-time load duration curves: Calendar years 2003 to 2007



45 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 *2007 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of accounting load.

PJM Real-Time, Annual Average Load

Table 2-43 presents summary real-time load statistics for the 10-year period 1998 to 2007. The average load of 81,681 MWh in 2007 was 2.8 percent higher than the 2006 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.[46]

Table 2-43 PJM real-time average load: Calendar years 1998 to 2007

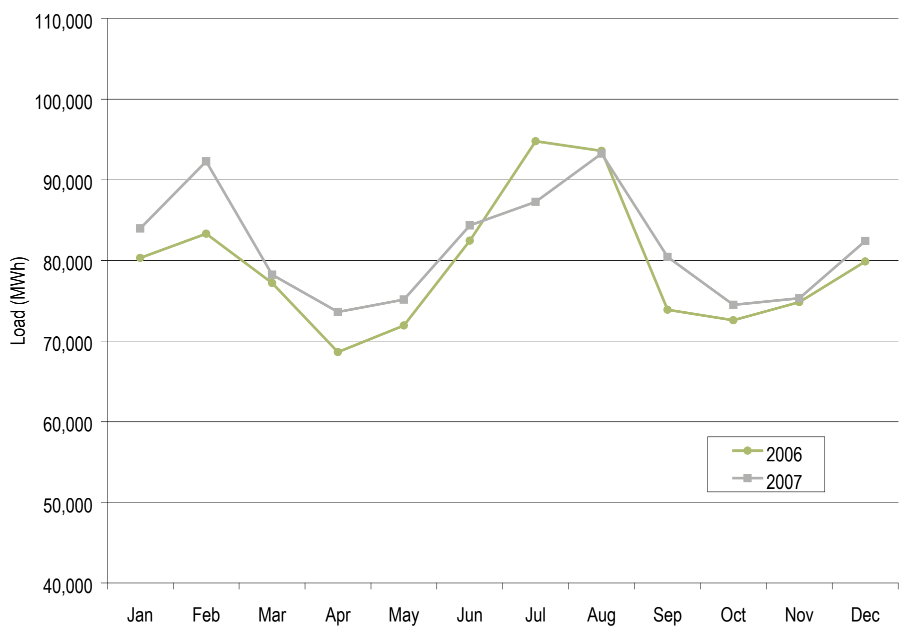
	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,577	28,653	5,512	NA	NA	NA
1999	29,640	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,797	34,804	7,964	18.2%	15.2%	35.6%
2003	37,395	37,029	6,834	4.5%	6.4%	(14.2%)
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%

46 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.

PJM Real-Time, Monthly Average Load

Figure 2-7 compares the real-time, monthly average hourly loads of 2007 with those of 2006.

Figure 2-7 PJM real-time average load: Calendar years 2006 to 2007



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).[47] THI is a measure of effective temperature using temperature and relative humidity. Table 2-44 shows the monthly minimum, average and maximum of the PJM hourly THI for the cooling months in 2006 and 2007. When comparing 2007 to 2006, changes in THI were mixed, consistent with the changes in load. For the cooling months of 2007, the average THI was 70.90, 0.6 percent lower than the average 71.30 THI for 2006. However, the maximum THI (82.84) and minimum THI (55.46) in 2007 were 1.8 percent lower and 4.2 percent higher, respectively, than the maximum THI (84.39) and minimum THI (53.22) in 2006 during the cooling months.

47 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" (June 1, 2007), Section 4, pp. 18-23.

Table 2-44 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2006 and 2007

	2006			2007			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	53.22	67.82	78.65	55.46	69.18	80.94	4.2%	2.0%	2.9%
Jul	58.23	73.63	82.17	55.78	70.92	80.29	(4.2%)	(3.7%)	(2.3%)
Aug	58.71	72.32	84.39	61.60	72.53	82.84	4.9%	0.3%	(1.8%)

Day-Ahead Load

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

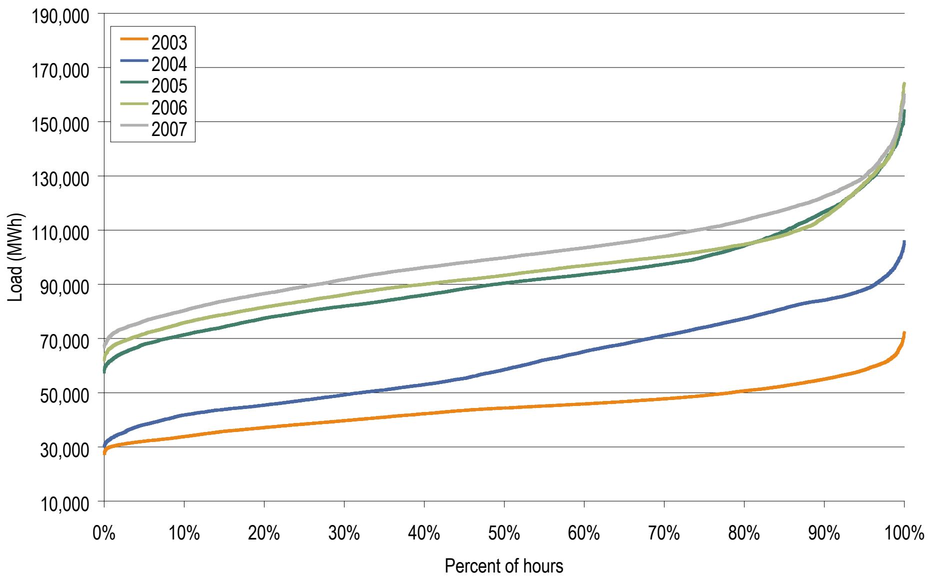
- Fixed-Demand Bid. Bid to purchase a defined MWh level of energy, regardless of LMP.
- Price-Sensitive Bid. Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- Decrement Bid (DEC). Financial bid to purchase a defined MWh level of energy up to 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 2-8 shows PJM day-ahead load duration curves from 2003 to 2007.

Figure 2-8 PJM day-ahead load duration curves: Calendar years 2003 to 2007



PJM Day-Ahead, Annual Average Load

Table 2-45 presents summary day-ahead load statistics for the five-year period 2003 to 2007. The average load of 100,912 MWh in 2007 was 6.5 percent higher than the 2006 annual average load. The cleared decrement bids, fixed demand and price-sensitive demand in 2007 were 18.8 percent, 3.6 percent and 1.0 percent higher than the corresponding loads in 2006, respectively.

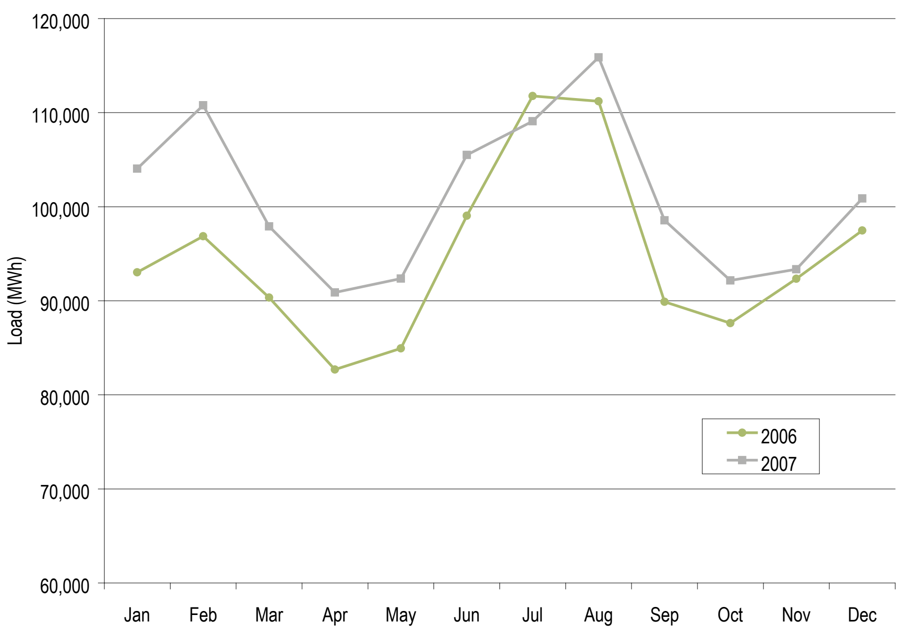
Table 2-45 PJM day-ahead average load: Calendar years 2003 to 2007

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2003	44,328	44,362	7,877	NA	NA	NA
2004	61,034	58,544	16,320	37.7%	32.0%	107.2%
2005	92,002	90,424	17,382	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%

PJM Day-Ahead, Monthly Average Load

Figure 2-9 compares the day-ahead, monthly average loads of 2007 with those of 2006.

Figure 2-9 PJM day-ahead average load: Calendar years 2006 to 2007



Real-Time and Day-Ahead Load

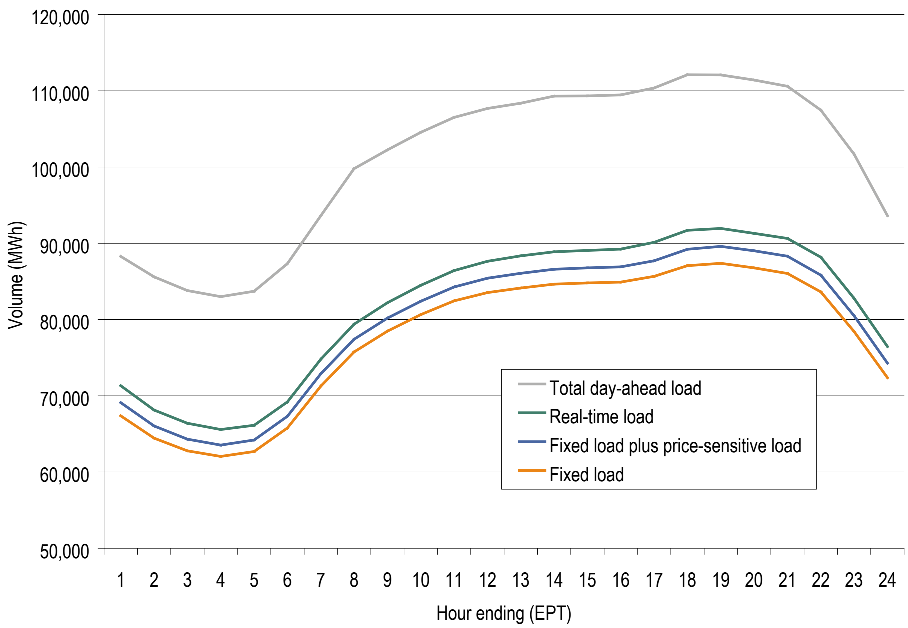
Table 2-46 presents summary statistics for the 2007 day-ahead and real-time loads and the average difference between them. The sum of day-ahead cleared fixed demand and price-sensitive demand averaged 2,184 MWh less than real-time average load. Total day-ahead load (the sum of the three types of cleared demand bids) averaged 19,231 MWh more than real-time load. Table 2-46 shows that, at 76.9 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 21.2 percent of day-ahead load.

Table 2-46 Cleared day-ahead and real-time load (MWh): Calendar year 2007

	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	77,628	1,869	21,415	100,912	81,681	19,231	(2,184)
Median	77,112	1,788	20,989	99,799	80,914	18,885	(2,104)
Standard deviation	13,659	503	2,733	16,190	14,618	1,572	(1,161)

Figure 2-10 shows the average 2007 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 2007, 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 10.5 percent of the hours. When cleared decrement bids are included, day-ahead load always exceeded real-time load.

Figure 2-10 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2007



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,[48] 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.[49]

- 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.

48 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 *2007 State of the Market Report,* Volume II, Section 2, "Energy Market, Part 1."

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

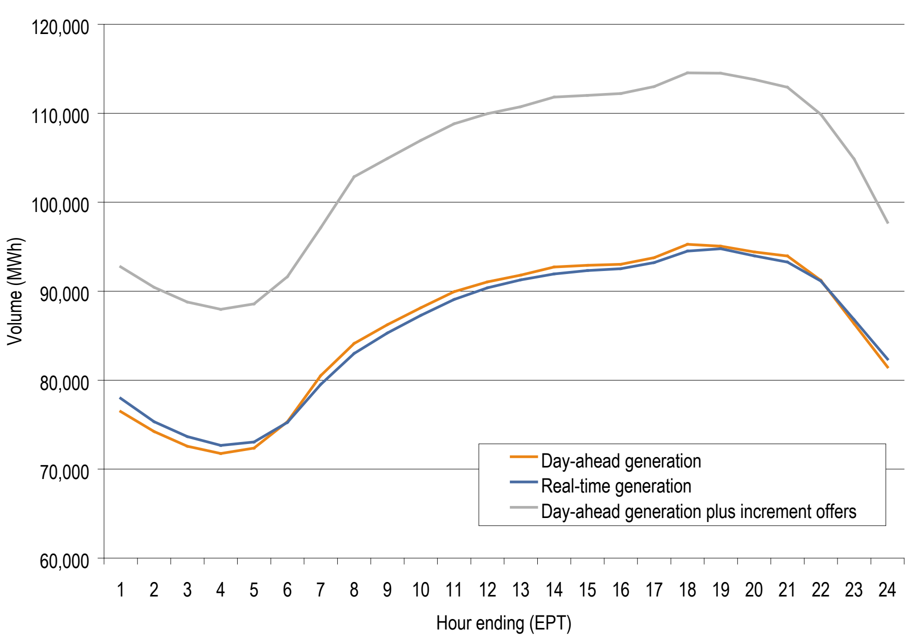
Table 2-47 presents summary statistics for 2007 day-ahead and real-time generation and the average differences between them. Day-ahead cleared generation from physical units averaged 170 MWh higher than real-time generation. Day-ahead cleared generation plus cleared INC offers averaged 18,256 MWh more than real-time generation. Table 2-47 also shows that cleared generation and INC offers accounted for 82.6 percent and 17.4 percent of day-ahead supply, respectively.

Table 2-47 Day-ahead and real-time generation (MWh): Calendar year 2007

	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	86,030	18,086	104,116	85,860	170	18,256
Median	84,743	17,708	102,517	84,046	697	18,471
Standard deviation	14,085	2,463	16,071	14,018	67	2,053

Figure 2-11 shows average hourly cleared volumes of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2007.[50] Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. During 2007, real-time, hourly average generation was lower than day-ahead generation from physical units, although the reverse was true for 45.1 percent of the hours. When cleared increment offers are included, average hourly total day-ahead cleared MW offers exceeded real-time generation.

Figure 2-11 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2007



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

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.[51]

Real-Time LMP

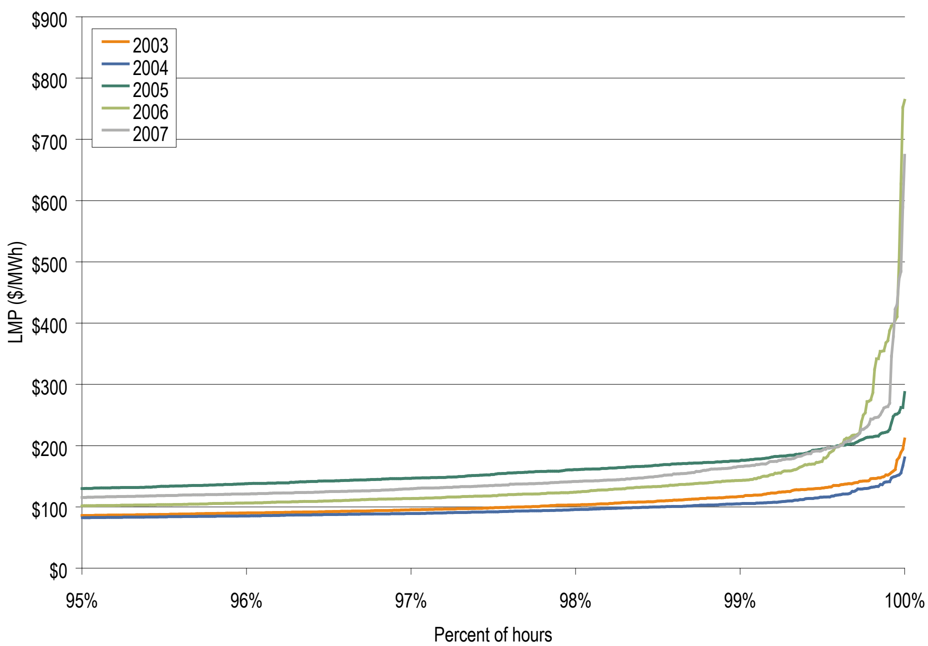
Real-time LMP is the hourly LMP for the PJM Real-Time Energy Market.

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 2-12 presents price duration curves for hours above the 95th percentile from 2003 to 2007. As Figure 2-12 shows, LMPs were less than $100 per MWh during 95 percent or more of the hours for the years 2003 and 2004 and less than $150 during 95 percent or more of the hours for the years 2005 to 2007.[52]

Figure 2-12 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2003 to 2007



51 See the *2007 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.

52 See the *2007 State of the Market Report,* Volume II, Appendix C, "Energy Market," at Table C-4, "Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2003 to 2007."

PJM Real-Time, Annual Average LMP

Table 2-48 shows the PJM real-time, annual, simple average LMP for the 10-year period 1998 to 2007.[53] The system simple average LMP for 2007 was 16.9 percent higher than the 2006 annual average, $57.58 per MWh versus $49.27 per MWh.

Table 2-48 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 to 2007

	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	$22.40	(12.6%)	(8.3%)	(50.3%)
2003	$38.27	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%

Zonal Real-Time, Annual Average LMP

Table 2-49 shows PJM zonal real-time, simple average LMP for 2006 and 2007. The largest zonal increase was in the JCPL Control Zone which experienced a $13.94 increase over 2006 and the smallest increase was in the ComEd Control Zone which experienced a $4.19 increase over 2006.

53 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 Zonal real-time, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AECO	$55.53	$65.02	$9.49	17.1%
AEP	$42.24	$46.55	$4.31	10.2%
AP	$48.71	$57.45	$8.74	17.9%
BGE	$57.40	$69.79	$12.39	21.6%
ComEd	$41.52	$45.71	$4.19	10.1%
DAY	$41.21	$46.47	$5.26	12.8%
DLCO	$39.34	$43.93	$4.59	11.7%
Dominion	$56.44	$66.75	$10.31	18.3%
DPL	$53.09	$64.15	$11.06	20.8%
JCPL	$51.80	$65.74	$13.94	26.9%
Met-Ed	$52.66	$64.57	$11.91	22.6%
PECO	$52.40	$62.60	$10.20	19.5%
PENELEC	$46.64	$54.80	$8.16	17.5%
Pepco	$58.85	$70.33	$11.48	19.5%
PPL	$51.52	$62.02	$10.50	20.4%
PSEG	$54.57	$65.92	$11.35	20.8%
RECO	$53.88	$64.85	$10.97	20.4%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-50 shows the real-time, simple average LMP for all or part of the jurisdictions within the PJM footprint during 2006 and 2007. The largest increase was in Maryland which experienced a $12.06 increase over 2006, and the smallest increase was in Tennessee which experienced a $2.68 increase over 2006.

Table 2-50 Jurisdiction real-time, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
Delaware	$52.74	$63.45	$10.71	20.3%
Illinois	$41.52	$45.71	$4.19	10.1%
Indiana	$41.65	$46.24	$4.59	11.0%
Kentucky	$42.52	$46.52	$4.00	9.4%
Maryland	$57.55	$69.61	$12.06	21.0%
Michigan	$41.73	$46.82	$5.09	12.2%
New Jersey	$53.94	$65.78	$11.84	22.0%
North Carolina	$54.06	$62.58	$8.52	15.8%
Ohio	$40.98	$45.69	$4.71	11.5%
Pennsylvania	$49.38	$58.72	$9.34	18.9%
Tennessee	$44.64	$47.32	$2.68	6.0%
Virginia	$54.83	$63.83	$9.00	16.4%
West Virginia	$42.48	$48.39	$5.91	13.9%
District of Columbia	$59.05	$70.25	$11.20	19.0%

Hub Real-Time, Annual Average LMP

Table 2-51 shows the real-time, simple average LMPs at the PJM hubs for 2006 and 2007. Hub prices are average LMPs across a defined set of buses, created to provide market participants with trading points that exhibited greater price stability than individual buses. The largest price increase was for the New Jersey Hub which experienced an $11.85 increase over 2006, and the smallest increase was for the AEP Gen Hub which experienced a $3.44 increase over 2006.

Table 2-51 Hub real-time, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AEP Gen Hub	$40.70	$44.14	$3.44	8.5%
AEP-DAY Hub	$41.43	$46.25	$4.82	11.6%
Chicago Gen Hub	$41.37	$45.11	$3.74	9.0%
Chicago Hub	$41.53	$45.76	$4.23	10.2%
Dominion Hub	$55.51	$64.65	$9.14	16.5%
Eastern Hub	$53.07	$63.92	$10.85	20.4%
N Illinois Hub	$41.45	$45.47	$4.02	9.7%
New Jersey Hub	$53.77	$65.62	$11.85	22.0%
Ohio Hub	$41.44	$46.18	$4.74	11.4%
West Interface Hub	$45.56	$51.67	$6.11	13.4%
Western Hub	$51.11	$59.77	$8.66	16.9%

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 2-52 shows the PJM real-time, annual, load-weighted, average LMP for the 10-year period 1998 to 2007. The load-weighted, average system LMP for 2007 was 15.6 percent higher than the 2006 annual, load-weighted, average, $61.66 per MWh versus $53.35 per MWh.

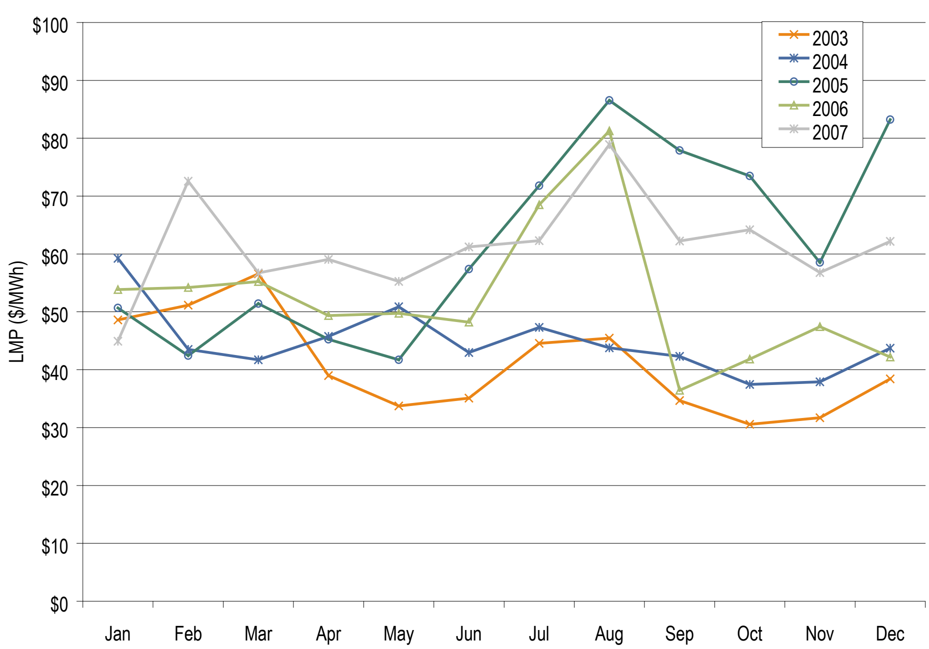
Table 2-52 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2007

	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	$31.58	$23.40	$26.73	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.95	$25.40	30.6%	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%)

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

Figure 2-13 shows the PJM real-time, monthly, load-weighted LMP from 2003 through 2007.

Figure 2-13 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2003 to 2007



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

Table 2-53 shows PJM zonal real-time, load-weighted, average LMP for 2006 and 2007. The largest zonal increase was in the JCPL Control Zone which experienced a $13.76 increase over 2006, and the smallest increase was in the ComEd Control Zone which experienced a $4.23 increase over 2006.

Table 2-53 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AECO	$62.32	$71.43	$9.11	14.6%
AEP	$44.85	$49.51	$4.66	10.4%
AP	$52.06	$61.20	$9.14	17.6%
BGE	$63.54	$75.95	$12.41	19.5%
ComEd	$45.05	$49.28	$4.23	9.4%
DAY	$44.28	$49.95	$5.67	12.8%
DLCO	$42.31	$47.23	$4.92	11.6%
Dominion	$62.27	$72.51	$10.24	16.4%
DPL	$58.28	$69.35	$11.07	19.0%
JCPL	$58.12	$71.88	$13.76	23.7%
Met-Ed	$57.18	$69.38	$12.20	21.3%
PECO	$57.03	$67.13	$10.10	17.7%
PENELEC	$49.13	$57.71	$8.58	17.5%
Pepco	$65.57	$76.75	$11.18	17.1%
PPL	$55.49	$66.12	$10.63	19.2%
PSEG	$59.73	$70.80	$11.07	18.5%
RECO	$59.79	$70.69	$10.90	18.2%

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

Table 2-54 shows the real-time, load-weighted, average LMPs for all or part of the jurisdictions within the PJM footprint during 2006 and 2007[54]. The largest increase was in Maryland which experienced a $12.00 increase over 2006, and the smallest increase was in Tennessee which experienced a $2.41 increase over 2006.

54 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 *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

Table 2-54 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
Delaware	$57.49	$68.19	$10.70	18.6%
Illinois	$45.05	$49.27	$4.22	9.4%
Indiana	$43.99	$48.79	$4.80	10.9%
Kentucky	$45.40	$50.16	$4.76	10.5%
Maryland	$64.05	$76.05	$12.00	18.7%
Michigan	$44.78	$50.09	$5.31	11.9%
New Jersey	$59.62	$71.21	$11.59	19.4%
North Carolina	$59.06	$67.95	$8.89	15.1%
Ohio	$43.77	$48.70	$4.93	11.3%
Pennsylvania	$53.05	$62.54	$9.49	17.9%
Tennessee	$47.82	$50.23	$2.41	5.0%
Virginia	$60.18	$69.21	$9.03	15.0%
West Virginia	$44.72	$51.31	$6.59	14.7%
District of Columbia	$64.37	$75.34	$10.97	17.0%

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 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.[55] To account for the changes in fuel cost between 2006 and 2007, the 2007 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.[56]

Before 2006, fuel-cost-adjusted LMP was calculated using monthly average fuel costs and an index number approach. The use of daily fuel prices and sensitivity factors for each marginal unit permits a more accurate adjustment and allows analysis for any aggregation of buses, e.g., zones.

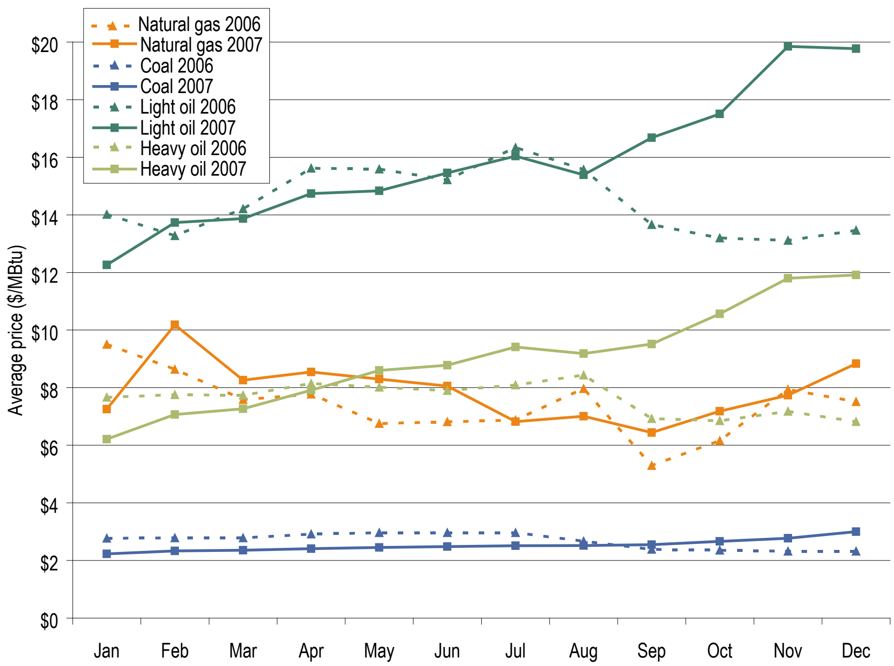
The dominant fuels in PJM, coal declined in price in 2007 and natural gas increased in price in 2007. In 2007, coal prices were 5.9 percent lower than in 2006. Natural gas prices were 6.4 percent higher in 2007 than in 2006. No. 2 (light) oil prices were 9.7 percent higher and No. 6 (heavy) oil prices were 18.4 percent higher in 2007 than in 2006.

55 See the *2007 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 2007."

56 For more information, see the *2007 State of the Market Report,* Volume II, Appendix K, "Calculation and Use of Generator Sensitivity Factors."

Since September 2007, the prices for light oil and heavy oil had been much higher than those during the corresponding period in 2006. From September to December in 2007, coal prices were 17.1 percent higher, natural gas prices were 12.3 percent higher, No. 2 (light) oil prices were 38.2 percent and No. 6 (heavy) oil prices were 57.8 percent higher than the corresponding fuel prices during the same months in 2006. Figure 2-14 shows average, daily delivered coal, natural gas and oil prices for units within PJM.[57]

Figure 2-14 Spot average fuel price comparison: Calendar years 2006 to 2007



57 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.

Figure 2-15 shows average, daily settled prices for NO_x and SO_2 emission within PJM. In 2007, NO_x prices were 56.5 percent lower than in 2006. SO_2 prices were 28.6 percent lower in 2007 than in 2006.

Figure 2-15 Spot average emission price comparison: Calendar years 2006 to 2007

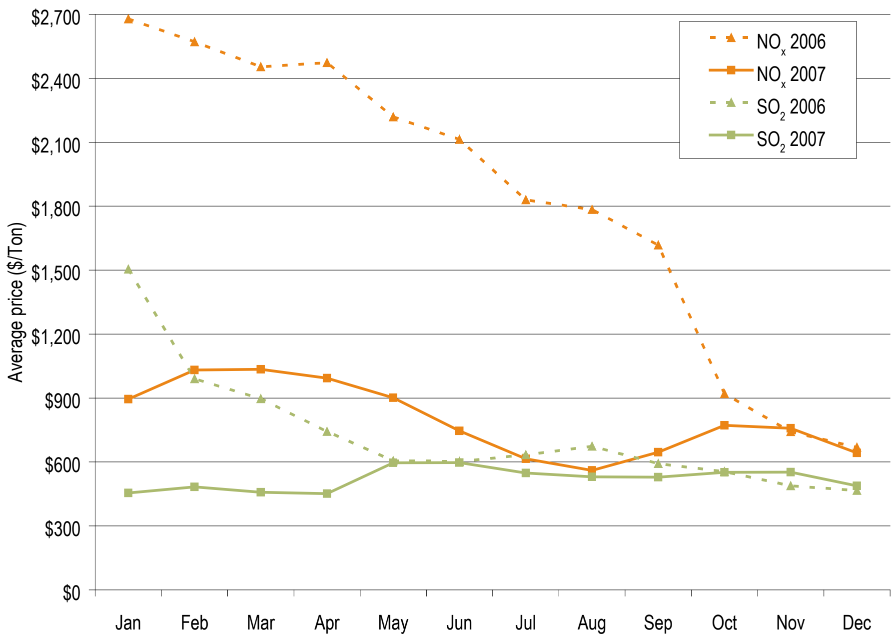


Table 2-55 compares the 2007 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2006 load-weighted, average LMP. The load-weighted, average LMP for 2007 was 15.6 percent higher than the load-weighted, average LMP for 2006. The fuel-cost-adjusted, load-weighted, average LMP in 2007 was 18.1 percent higher than the load-weighted LMP in 2006. If fuel costs for the year 2007 had been the same as for 2006, the 2007 load-weighted LMP would have been higher, $63.00 per MWh instead of $61.66 per MWh. Lower coal prices in 2007 resulted in lower prices in 2007 than would have occurred if coal prices had remained the same, offset in part by higher prices for natural gas and oil. Net fuel-cost increases were a part (16.13 percent) of the reason for higher LMP in 2007, but prices would have been higher in 2007 even if fuel costs had remained at 2006 levels.

Table 2-55 PJM annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2006 Load-Weighted LMP	2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$53.35	$63.00	18.1%
Median	$44.40	$54.55	22.9%
Standard deviation	$37.81	$35.36	(6.5%)

Table 2-56 compares the 2007 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2006 load-weighted, average LMP on a monthly basis.

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

	2006 Load-Weighted LMP	2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Jan	$53.86	$60.10	11.6%
Feb	$54.21	$79.02	45.8%
Mar	$55.23	$63.82	15.6%
Apr	$49.34	$64.44	30.6%
May	$49.74	$56.84	14.3%
Jun	$48.22	$62.92	30.5%
Jul	$68.51	$69.12	0.9%
Aug	$81.28	$85.52	5.2%
Sep	$36.43	$55.60	52.6%
Oct	$41.83	$51.08	22.1%
Nov	$47.43	$49.50	4.4%
Dec	$42.20	$51.36	21.7%

Table 2-57 compares the 2007 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2006 load-weighted, average LMP on a zonal basis.

Table 2-57 Zonal fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Calendar year 2007

	2006 Load-Weighted LMP	2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
AECO	$62.32	$71.87	15.3%
AEP	$44.85	$52.00	15.9%
AP	$52.06	$62.34	19.7%
BGE	$63.54	$76.48	20.4%
ComEd	$45.05	$51.76	14.9%
DAY	$44.28	$52.56	18.7%
DLCO	$42.31	$49.59	17.2%
Dominion	$62.27	$73.42	17.9%
DPL	$58.28	$69.98	20.1%
JCPL	$58.12	$72.04	23.9%
Met-Ed	$57.18	$69.99	22.4%
PECO	$57.03	$67.37	18.1%
PENELEC	$49.13	$59.07	20.2%
Pepco	$65.57	$77.21	17.7%
PPL	$55.49	$66.74	20.3%
PSEG	$59.73	$70.49	18.0%
RECO	$59.79	$70.92	18.6%

Table 2-58 compares the PJM fuel-cost-adjusted, load-weighted, average LMP in 2007 to the 2006 load-weighted, average LMP based on jurisdiction.

Table 2-58 Jurisdiction fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Calendar year 2007

	2006 Load-Weighted LMP	2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Delaware	$57.49	$68.84	19.7%
Illinois	$45.05	$51.76	14.9%
Indiana	$43.99	$51.29	16.6%
Kentucky	$45.40	$52.98	16.7%
Maryland	$64.05	$76.58	19.6%
Michigan	$44.78	$52.53	17.3%
New Jersey	$59.62	$71.13	19.3%
North Carolina	$59.06	$69.54	17.7%
Ohio	$43.77	$51.27	17.1%
Pennsylvania	$53.05	$63.48	19.7%
Tennessee	$47.82	$52.47	9.7%
Virginia	$60.18	$70.33	16.9%
West Virginia	$44.72	$53.64	19.9%
District of Columbia	$64.37	$75.75	17.7%

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.

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 2-59 shows that 35.0 percent of the annual, load-weighted LMP was the result of coal costs; 28.4 percent was the result of gas costs and 7.0 percent was the result of the cost of SO_2 emission allowances. Fuel costs, overall, accounted for 82.3 percent of marginal cost and for 69.8 percent of LMP.

In some cases, the bus price for the marginal unit may not equal the calculated price based on the offer curve of the marginal unit. These differences are the result of unit dispatch constraints and transmission constraints and the interactions among them. Any difference between the price based on the offer curve and the actual bus price for marginal units is defined as the “constrained off” component. In addition, final LMPs calculated using sensitivity factors may differ slightly from PJM’s posted LMPs as a result of rounding and missing data. This differential is identified as “NA” in Table 2-59.

Table 2-59 Components of PJM annual, load-weighted, average LMP: Calendar year 2007

Element	Contribution to LMP	Percent
Coal	$21.57	35.0%
Gas	$17.50	28.4%
Oil	$3.97	6.4%
Wind	$0.01	0.0%
SO_2	$4.33	7.0%
VOM	$4.16	6.7%
Markup	$5.86	9.5%
Constrained off	$3.13	5.1%
NO_x	$0.74	1.2%
NA	$0.39	0.6%

Day-Ahead LMP

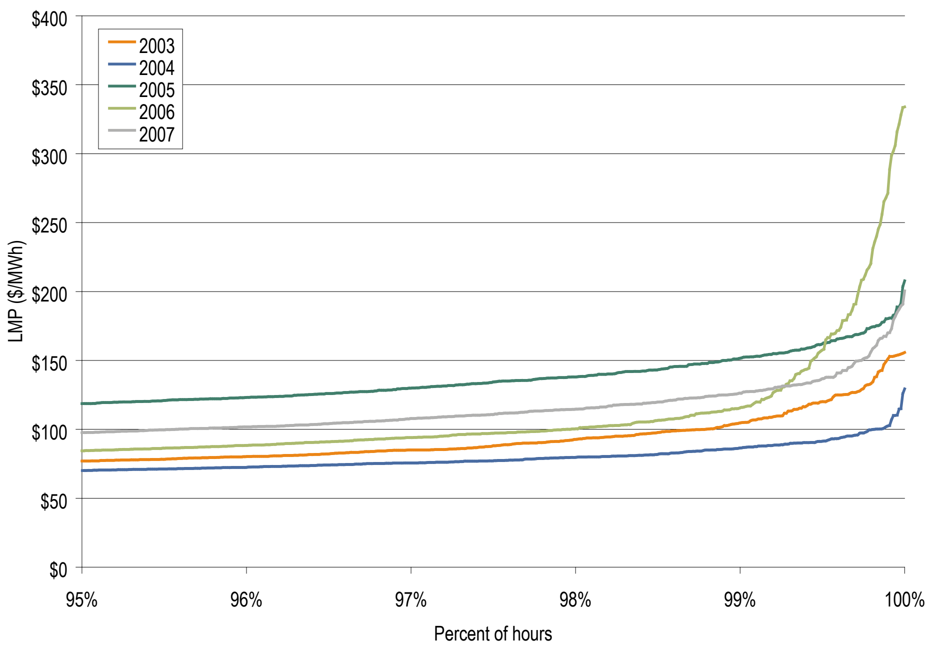
Day-ahead LMP is the hourly LMP for the PJM Day-Ahead Energy Market.

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 2-16 presents day-ahead price duration curves for hours above the 95th percentile from 2003 to 2007. As Figure 2-16 shows, day-ahead LMP was less than $100 per MWh during 95 percent or more of the hours for the years 2003, 2004, 2006 and 2007 and less than $150 during 95 percent or more of the hours for 2005.

Figure 2-16 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2003 to 2007



PJM Day-Ahead, Annual Average LMP

Table 2-60 shows the PJM day-ahead annual, simple average LMP for the five-year period 2003 to 2007. The system simple average LMP for 2007 was 13.7 percent higher than the 2006 annual average, $54.67 per MWh versus $48.10 per MWh.

Table 2-60 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2003 to 2007

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2003	$38.72	$35.21	$20.84	NA	NA	NA
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.3%)
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%

Zonal Day-Ahead, Annual Average LMP

Table 2-61 shows PJM zonal day-ahead, simple average LMP for 2006 and 2007. The largest zonal increase was in the JCPL Control Zone which experienced an $11.95 increase over 2006 and the smallest increase was in the AEP Control Zone which experienced a $4.15 increase over 2006.

Table 2-61 Zonal day-ahead, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AECO	$54.58	$62.96	$8.38	15.4%
AEP	$41.40	$45.55	$4.15	10.0%
AP	$47.33	$54.88	$7.55	16.0%
BGE	$55.51	$65.37	$9.86	17.8%
ComEd	$41.04	$45.35	$4.31	10.5%
DAY	$40.33	$45.29	$4.96	12.3%
DLCO	$38.96	$43.75	$4.79	12.3%
Dominion	$54.58	$63.42	$8.84	16.2%
DPL	$52.99	$61.95	$8.96	16.9%
JCPL	$51.23	$63.18	$11.95	23.3%
Met-Ed	$52.64	$61.62	$8.98	17.1%
PECO	$52.46	$61.25	$8.79	16.8%
PENELEC	$46.08	$52.97	$6.89	15.0%
Pepco	$56.78	$66.44	$9.66	17.0%
PPL	$51.48	$60.00	$8.52	16.6%
PSEG	$53.68	$63.94	$10.26	19.1%
RECO	$53.63	$63.37	$9.74	18.2%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-62 shows PJM's day-ahead, simple average LMPs for 2006 and 2007, by jurisdiction. The largest increase was in New Jersey which experienced a $10.47 increase over 2006, and the smallest increase was in Tennessee which experienced a $2.84 increase over 2006.

Table 2-62 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
Delaware	$52.72	$61.40	$8.68	16.5%
Illinois	$41.04	$45.34	$4.30	10.5%
Indiana	$40.74	$45.47	$4.73	11.6%
Kentucky	$41.43	$45.40	$3.97	9.6%
Maryland	$55.79	$65.64	$9.85	17.7%
Michigan	$40.80	$46.00	$5.20	12.7%
New Jersey	$53.12	$63.59	$10.47	19.7%
North Carolina	$52.56	$59.83	$7.27	13.8%
Ohio	$40.03	$44.71	$4.68	11.7%
Pennsylvania	$49.03	$56.84	$7.81	15.9%
Tennessee	$43.68	$46.52	$2.84	6.5%
Virginia	$53.44	$61.01	$7.57	14.2%
West Virginia	$41.33	$46.54	$5.21	12.6%
District of Columbia	$56.54	$66.40	$9.86	17.4%

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 2-63 shows the PJM day-ahead, annual, load-weighted, average LMP for the five-year period 2003 to 2007. The day-ahead, load-weighted, average LMP for 2007 was 12.8 percent higher than the 2006 annual, load-weighted, average, at $57.88 per MWh versus $51.33 per MWh.

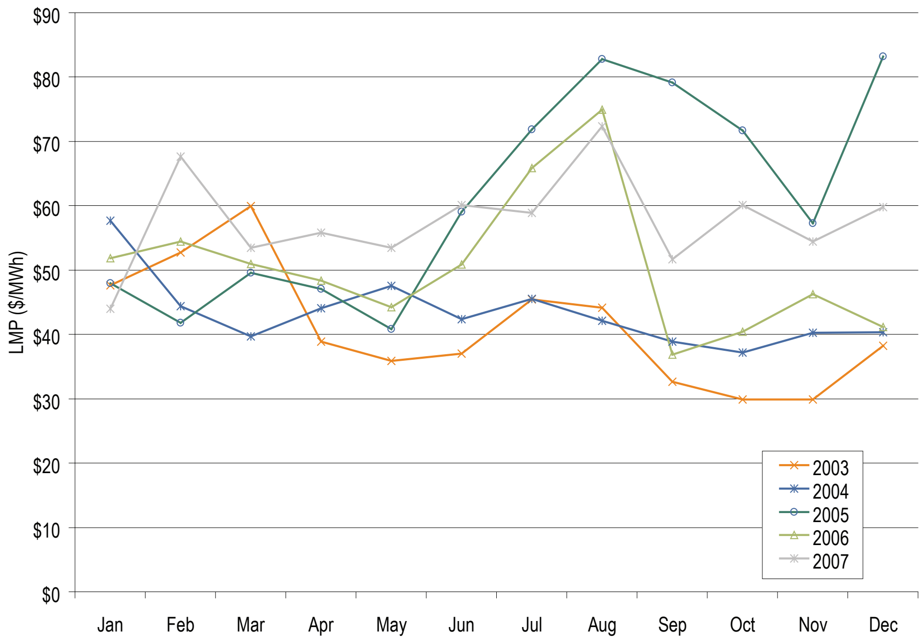
Table 2-63 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2003 to 2007

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2003	$41.42	$38.29	$21.32	NA	NA	NA
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.5%)
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%)

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

Figure 2-17 shows the PJM day-ahead, monthly, load-weighted LMP from 2003 through 2007.

Figure 2-17 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2003 to 2007



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-64 shows PJM's zonal day-ahead, load-weighted, average LMPs for 2006 and 2007. The largest zonal increase was in the JCPL Control Zone which experienced an $11.32 increase over 2006, and the smallest increase was in the ComEd Control Zone which experienced a $3.93 increase over 2006.

Table 2-64 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AECO	$61.73	$69.11	$7.38	12.0%
AEP	$43.68	$48.26	$4.58	10.5%
AP	$49.58	$57.34	$7.76	15.7%
BGE	$61.00	$70.22	$9.22	15.1%
ComEd	$43.34	$47.27	$3.93	9.1%
DAY	$43.02	$48.43	$5.41	12.6%
DLCO	$41.64	$46.99	$5.35	12.8%
Dominion	$59.57	$68.08	$8.51	14.3%
DPL	$58.57	$66.84	$8.27	14.1%
JCPL	$57.02	$68.34	$11.32	19.9%
Met-Ed	$57.51	$65.36	$7.85	13.6%
PECO	$56.46	$65.21	$8.75	15.5%
PENELEC	$47.61	$55.44	$7.83	16.4%
Pepco	$60.64	$70.50	$9.86	16.3%
PPL	$55.00	$63.52	$8.52	15.5%
PSEG	$57.96	$68.01	$10.05	17.3%
RECO	$59.23	$68.88	$9.65	16.3%

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

Table 2-65 shows PJM's day-ahead, load-weighted, average LMPs for 2006 and 2007 by jurisdiction. The largest increase was in the District of Columbia which experienced a $10.25 increase over 2006, and the smallest increase was in Tennessee which experienced a $3.39 increase over 2006.

Table 2-65 Jurisdiction day-ahead, load-weighted LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
Delaware	$57.98	$66.03	$8.05	13.9%
Illinois	$43.34	$47.26	$3.92	9.0%
Indiana	$43.15	$48.24	$5.09	11.8%
Kentucky	$43.52	$48.07	$4.55	10.5%
Maryland	$60.51	$70.21	$9.70	16.0%
Michigan	$43.48	$48.72	$5.24	12.1%
New Jersey	$58.20	$68.21	$10.01	17.2%
North Carolina	$57.38	$65.04	$7.66	13.3%
Ohio	$42.36	$47.41	$5.05	11.9%
Pennsylvania	$52.03	$60.06	$8.03	15.4%
Tennessee	$45.93	$49.32	$3.39	7.4%
Virginia	$57.92	$65.32	$7.40	12.8%
West Virginia	$43.43	$49.20	$5.77	13.3%
District of Columbia	$59.82	$70.07	$10.25	17.1%

Marginal Losses

Marginal losses are the incremental change in system real power losses caused by changes in the system load and generation patterns.[58] 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.[59] 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 2-66 shows the PJM real-time, simple average LMP components, including the loss component, for calendar years 2006 and 2007. Effective 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

58 For additional information, see the *2007 State of the Market Report*, Volume II, Appendix J, "Marginal Losses."

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

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 2-66 shows a $0.02 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 $0.02 loss component of the average PJM system price results from these different weights. The $1.00 congestion component of the average PJM system price results from the fact that the average is calculated over the entire calendar year, but only six months included a distributed load reference bus.

Table 2-66 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 and 2007

	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

Table 2-67 shows the zonal real-time, simple average LMP components, including the loss component, for calendar years 2006 and 2007.

Table 2-67 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 and 2007.

	2006				2007			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$55.53	$47.19	$8.34	$0.0	$65.02	$56.56	$6.42	$2.04
AEP	$42.24	$47.19	($4.95)	$0.0	$46.55	$56.56	($8.80)	($1.21)
AP	$48.71	$47.19	$1.52	$0.0	$57.45	$56.56	$1.33	($0.44)
BGE	$57.40	$47.19	$10.21	$0.0	$69.79	$56.56	$12.08	$1.15
ComEd	$41.52	$47.19	($5.67)	$0.0	$45.71	$56.56	($9.42)	($1.43)
DAY	$41.21	$47.19	($5.98)	$0.0	$46.47	$56.56	($9.54)	($0.55)
Dominion	$56.44	$47.19	$9.25	$0.0	$66.75	$56.56	$9.89	$0.30
DPL	$53.09	$47.19	$5.90	$0.0	$64.15	$56.56	$6.09	$1.50
DLCO	$39.34	$47.19	($7.85)	$0.0	$43.93	$56.56	($11.13)	($1.50)
JCPL	$51.80	$47.19	$4.61	$0.0	$65.74	$56.56	$7.36	$1.82
Met-Ed	$52.66	$47.19	$5.47	$0.0	$64.57	$56.56	$7.32	$0.69
PECO	$52.40	$47.19	$5.21	$0.0	$62.60	$56.56	$4.82	$1.22
PENELEC	$46.64	$47.19	($0.55)	$0.0	$54.80	$56.56	($1.46)	($0.30)
Pepco	$58.85	$47.19	$11.66	$0.0	$70.33	$56.56	$13.00	$0.77
PPL	$51.52	$47.19	$4.33	$0.0	$62.02	$56.56	$4.89	$0.57
PSEG	$54.57	$47.19	$7.38	$0.0	$65.92	$56.56	$7.43	$1.93
RECO	$53.88	$47.19	$6.69	$0.0	$64.85	$56.56	$6.50	$1.79

Table 2-68 shows the real-time, annual, simple average LMP components from June 1, 2007, to December 31, 2007, for each zone and PJM.

Table 2-68 Zonal and PJM real-time, simple average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$69.18	$59.49	$6.21	$3.48
AEP	$47.28	$59.49	($10.16)	($2.06)
AP	$58.50	$59.49	($0.25)	($0.75)
BGE	$73.14	$59.49	$11.69	$1.96
ComEd	$46.00	$59.49	($11.05)	($2.45)
DAY	$47.32	$59.49	($11.24)	($0.93)
DLCO	$42.85	$59.49	($14.08)	($2.56)
Dominion	$69.73	$59.49	$9.72	$0.51
DPL	$67.09	$59.49	$5.04	$2.56
JCPL	$70.13	$59.49	$7.53	$3.10
Met-Ed	$67.42	$59.49	$6.75	$1.18
PECO	$65.04	$59.49	$3.47	$2.08
PENELEC	$56.22	$59.49	($2.75)	($0.52)
Pepco	$73.30	$59.49	$12.50	$1.31
PPL	$64.49	$59.49	$4.03	$0.97
PSEG	$68.68	$59.49	$5.89	$3.30
RECO	$67.97	$59.49	$5.43	$3.05
PJM	$59.56	$59.49	$0.02	$0.04

Table 2-69 shows the real-time, annual, simple average LMP loss component at the PJM hubs from June 1, 2007, to December 31, 2007, for each hub in PJM.

Table 2-69 Hub real-time, simple average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$43.58	$59.49	($11.70)	($4.21)
AEP-DAY Hub	$46.82	$59.49	($10.56)	($2.11)
Chicago Gen Hub	$44.97	$59.49	($11.19)	($3.34)
Chicago Hub	$46.07	$59.49	($11.00)	($2.43)
Dominion Hub	$67.47	$59.49	$8.04	($0.06)
Eastern Hub	$66.97	$59.49	$4.51	$2.97
N Illinois Hub	$45.57	$59.49	($11.06)	($2.86)
New Jersey Hub	$69.03	$59.49	$6.32	$3.21
Ohio Hub	$46.72	$59.49	($10.91)	($1.86)
West Interface Hub	$52.33	$59.49	($4.92)	($2.24)
Western Hub	$60.93	$59.49	$2.20	($0.77)

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 from June 1, 2007, to December 31, 2007.

Table 2-70 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$77.22	$65.41	$7.92	$3.88
AEP	$50.66	$63.35	($10.53)	($2.16)
AP	$62.81	$63.94	($0.33)	($0.81)
BGE	$80.48	$64.77	$13.50	$2.20
ComEd	$50.28	$63.81	($11.11)	($2.42)
DAY	$51.39	$64.06	($11.78)	($0.89)
DLCO	$46.85	$63.95	($14.38)	($2.71)
Dominion	$76.54	$64.96	$10.99	$0.59
DPL	$73.10	$65.03	$5.25	$2.82
JCPL	$77.64	$66.16	$8.15	$3.33
Met-Ed	$73.11	$64.37	$7.54	$1.20
PECO	$70.39	$64.55	$3.64	$2.20
PENELEC	$59.55	$63.17	($3.05)	($0.57)
Pepco	$80.85	$64.85	$14.52	$1.47
PPL	$69.31	$64.04	$4.27	$1.01
PSEG	$74.47	$64.84	$6.16	$3.48
RECO	$74.66	$66.05	$5.37	$3.24
PJM	$64.38	$64.31	$0.02	$0.05

Table 2-71 shows the PJM day-ahead, simple average LMP components, including the loss component, for calendar years 2006 and 2007. Effective June 1, 2007, 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): Calendar years 2006 and 2007

	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)

Table 2-72 shows the zonal day-ahead, simple average LMP components, including the loss component, for calendar years 2006 and 2007.

Table 2-72 Zonal day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 and 2007

	2006				2007			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$54.58	$46.45	$8.13	$0.0	$62.96	$54.60	$6.27	$2.09
AEP	$41.40	$46.45	($5.06)	$0.0	$45.55	$54.60	($7.59)	($1.46)
AP	$47.33	$46.45	$0.88	$0.0	$54.88	$54.60	$0.77	($0.49)
BGE	$55.51	$46.45	$9.06	$0.0	$65.37	$54.60	$9.50	$1.27
ComEd	$41.04	$46.45	($5.41)	$0.0	$45.35	$54.60	($7.80)	($1.45)
DAY	$40.33	$46.45	($6.12)	$0.0	$45.29	$54.60	($8.12)	($1.19)
DLCO	$38.96	$46.45	($7.49)	$0.0	$43.75	$54.60	($9.22)	($1.64)
DPL	$52.99	$46.45	$6.54	$0.0	$61.95	$54.60	$5.72	$1.63
Dominion	$54.58	$46.45	$8.13	$0.0	$63.42	$54.60	$8.42	$0.39
JCPL	$51.23	$46.45	$4.78	$0.0	$63.18	$54.60	$6.49	$2.09
Met-Ed	$52.64	$46.45	$6.19	$0.0	$61.62	$54.60	$6.24	$0.77
PECO	$52.46	$46.45	$6.01	$0.0	$61.25	$54.60	$5.01	$1.63
PENELEC	$46.08	$46.45	($0.37)	$0.0	$52.97	$54.60	($1.14)	($0.50)
Pepco	$56.78	$46.45	$10.33	$0.0	$66.44	$54.60	$10.83	$1.00
PPL	$51.48	$46.45	$5.03	$0.0	$60.00	$54.60	$4.75	$0.65
PSEG	$53.68	$46.45	$7.23	$0.0	$63.94	$54.60	$7.05	$2.29
RECO	$53.63	$46.45	$7.18	$0.0	$63.37	$54.60	$6.77	$2.00

Table 2-73 shows day-ahead, annual average LMP components from June 1, 2007, to December 31, 2007, for each zone and for PJM.

Table 2-73 Zonal and PJM day-ahead, simple average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$66.21	$56.97	$5.69	$3.56
AEP	$46.09	$56.97	($8.39)	($2.49)
AP	$55.73	$56.97	($0.40)	($0.84)
BGE	$68.51	$56.97	$9.38	$2.17
ComEd	$45.70	$56.97	($8.79)	($2.48)
DAY	$45.84	$56.97	($9.10)	($2.03)
DLCO	$42.83	$56.97	($11.34)	($2.79)
Dominion	$66.04	$56.97	$8.41	$0.67
DPL	$64.24	$56.97	$4.50	$2.78
JCPL	$66.81	$56.97	$6.28	$3.57
Met-Ed	$63.98	$56.97	$5.70	$1.32
PECO	$63.39	$56.97	$3.64	$2.79
PENELEC	$54.29	$56.97	($1.82)	($0.85)
Pepco	$69.53	$56.97	$10.86	$1.70
PPL	$61.95	$56.97	$3.88	$1.10
PSEG	$66.76	$56.97	$5.89	$3.90
RECO	$66.14	$56.97	$5.76	$3.41
PJM	$56.20	$56.97	($0.46)	($0.31)

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

Table 2-74 shows zonal and PJM day-ahead, annual, load-weighted, average LMP components from June 1, 2007, to December 31, 2007.

Table 2-74 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$73.66	$62.65	$7.05	$3.97
AEP	$49.19	$60.46	($8.65)	($2.62)
AP	$58.29	$59.65	($0.48)	($0.89)
BGE	$74.33	$61.60	$10.31	$2.42
ComEd	$48.15	$59.61	($9.00)	($2.46)
DAY	$49.32	$60.84	($9.42)	($2.10)
DLCO	$46.76	$61.64	($11.91)	($2.98)
Dominion	$71.43	$61.70	$9.02	$0.72
DPL	$70.03	$62.33	$4.68	$3.02
JCPL	$73.22	$62.70	$6.76	$3.76
Met-Ed	$68.57	$61.07	$6.19	$1.30
PECO	$68.14	$61.42	$3.76	$2.95
PENELEC	$57.10	$60.01	($2.01)	($0.90)
Pepco	$74.45	$60.81	$11.78	$1.87
PPL	$66.06	$60.90	$4.04	$1.12
PSEG	$71.64	$61.62	$5.96	$4.06
RECO	$72.15	$62.99	$5.61	$3.54
PJM	$60.01	$60.80	($0.47)	($0.33)

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 2-75 shows a monthly summary of marginal loss costs by type. Marginal loss costs totaled $1.247 billion. The highest monthly loss cost was in August and totaled $247.7 million or 19.8 percent of the total. The majority of the marginal loss costs was in the Day-Ahead Energy Market and totaled $1.261 billion. The day-ahead costs were offset, in part, by a total of -$14.1 million in the balancing market. The overcollected portion of transmission losses that was credited back to load plus exports as of December 31, 2007, was $630 million or 50.5 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.[60]

60 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.

Table 2-75 Marginal loss costs by type (Dollars (Millions)): June 1, 2007, to December 31, 2007

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jun	($30.7)	($198.8)	$8.7	$176.8	$2.4	$0.0	($3.6)	($1.2)	$175.5
Jul	($33.7)	($216.3)	$6.9	$189.5	$0.9	($0.4)	($2.7)	($1.4)	$188.1
Aug	($45.8)	($287.4)	$8.0	$249.6	$8.4	$8.5	($1.8)	($1.9)	$247.7
Sep	($24.3)	($167.4)	$6.8	$149.9	($4.1)	($5.7)	($1.7)	($0.1)	$149.8
Oct	($21.2)	($169.7)	$8.6	$157.1	($5.7)	($6.0)	($2.1)	($1.8)	$155.4
Nov	($20.0)	($159.7)	$7.8	$147.5	($8.9)	($7.1)	($2.8)	($4.6)	$142.9
Dec	($23.8)	($203.7)	$10.7	$190.6	($12.8)	($13.4)	($3.6)	($3.0)	$187.6
Total	($199.7)	($1,403.1)	$57.6	$1,261.0	($19.8)	($24.1)	($18.3)	($14.1)	$1,246.9

Zonal Marginal Loss Costs

Table 2-76 shows the marginal loss costs by type in each control zone. The AEP, ComEd and Dominion control zones had the highest marginal loss costs in 2007, with $266.2 million, $211.4 million and $130.7 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 2-76, the marginal loss generation credits in the western zones are generally greater in magnitude and negative relative to 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 2-76 Marginal loss costs by control zone and type (Dollars (Millions)): June 1, 2007, to December 31, 2007

	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	$28.1	$9.0	$0.4	$19.5	$29.2	$27.4	($0.3)	$1.5	$21.0
AEP	($284.9)	($556.2)	$9.6	$280.9	($184.5)	($168.7)	$1.0	($14.8)	$266.2
AP	($27.9)	($111.5)	$3.0	$86.5	($9.3)	($7.4)	($1.2)	($3.2)	$83.4
BGE	$56.9	$20.8	$1.9	$38.0	$46.8	$44.1	($1.6)	$1.0	$39.0
ComEd	($323.8)	($523.8)	$0.5	$200.6	($143.2)	($154.0)	$0.1	$10.9	$211.4
DAY	($28.1)	($73.0)	$1.4	$46.3	($10.6)	($7.5)	($0.0)	($3.1)	$43.1
DLCO	($64.2)	($86.6)	$0.0	$22.4	($28.9)	($22.7)	($0.0)	($6.2)	$16.1
DPL	$41.5	$13.3	$1.1	$29.2	$34.0	$32.0	($0.8)	$1.2	$30.4
Dominion	$35.1	($93.1)	$1.4	$129.6	$35.6	$33.9	($0.5)	$1.1	$130.7
JCPL	$65.6	$29.0	$0.7	$37.4	$54.6	$51.2	($0.6)	$2.8	$40.2
Met-Ed	$12.8	($0.6)	$1.1	$14.5	$0.8	($0.3)	$4.3	$5.4	$19.9
PECO	$154.7	$94.4	$0.3	$60.6	$3.0	$4.8	($0.2)	($1.9)	$58.7
PENELEC	($103.7)	($189.1)	$0.4	$85.8	$0.9	$1.9	$1.6	$0.6	$86.4
Pepco	$69.4	$34.6	$2.6	$37.4	$40.6	$39.1	($2.2)	($0.6)	$36.8
PJM	($10.1)	($10.6)	$25.5	$26.0	($1.4)	($7.4)	($13.8)	($7.9)	$18.2
PPL	$52.3	($10.0)	$1.4	$63.6	$4.4	$3.4	$0.5	$1.6	$65.2
PSEG	$123.5	$50.1	$6.1	$79.5	$104.8	$102.9	($4.7)	($2.8)	$76.8
RECO	$3.3	$0.1	$0.0	$3.2	$3.5	$3.1	($0.0)	$0.3	$3.5
Total	($199.7)	($1,403.1)	$57.6	$1,261.0	($19.8)	($24.1)	($18.3)	($14.1)	$1,246.9

Table 2-77 shows the monthly marginal loss cost, by control zone. With the exception of August, the marginal loss costs were distributed fairly evenly across all months.

Table 2-77 Monthly marginal loss costs by control zone (Dollars (Millions)): June 1, 2007, to December 31, 2007

Marginal Loss Costs by Control Zone (Millions)								
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$3.3	$4.0	$4.3	$2.3	$2.5	$2.2	$2.5	$21.0
AEP	$36.4	$40.1	$57.2	$32.4	$33.0	$28.7	$38.4	$266.2
AP	$11.9	$11.7	$16.8	$10.0	$11.8	$8.9	$12.2	$83.4
BGE	$5.4	$6.2	$8.0	$4.7	$5.2	$4.3	$5.2	$39.0
ComEd	$29.4	$31.1	$42.9	$28.0	$27.2	$23.6	$29.1	$211.4
DAY	$5.9	$6.2	$9.2	$5.3	$5.3	$5.0	$6.2	$43.1
DLCO	$2.8	$2.6	$2.6	$1.6	$1.2	$2.4	$3.0	$16.1
DPL	$4.2	$4.8	$5.5	$3.3	$4.0	$3.6	$5.0	$30.4
Dominion	$20.0	$21.7	$28.8	$16.1	$15.4	$12.3	$16.5	$130.7
JCPL	$5.6	$6.4	$5.7	$4.7	$5.0	$5.0	$7.8	$40.2
Met-Ed	$2.7	$3.0	$4.3	$2.4	$2.7	$2.1	$2.6	$19.9
PECO	$8.6	$9.7	$12.5	$6.4	$6.0	$6.4	$9.0	$58.7
PENELEC	$13.0	$12.9	$17.7	$9.9	$9.6	$10.1	$13.3	$86.4
Pepco	$5.0	$6.0	$7.4	$5.1	$5.4	$3.4	$4.5	$36.8
PJM	$0.7	($0.6)	($1.5)	$0.5	$3.4	$6.2	$9.4	$18.2
PPL	$8.4	$9.8	$13.7	$7.5	$7.5	$8.6	$9.8	$65.2
PSEG	$11.6	$11.9	$12.3	$9.0	$9.8	$9.8	$12.3	$76.8
RECO	$0.5	$0.6	$0.4	$0.4	$0.5	$0.5	$0.7	$3.5
Total	$175.5	$188.1	$247.7	$149.8	$155.4	$142.9	$187.6	$1,246.9

Price Convergence

The PJM Day-Ahead Energy Market, introduced on June 1, 2000, 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. 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 cause prices in the Day-Ahead and Real-Time Energy Markets to converge. 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 2-78 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 2007.[61] Together, increment offers and decrement bids represented 58.6 percent of the marginal bids or offers in 2007.

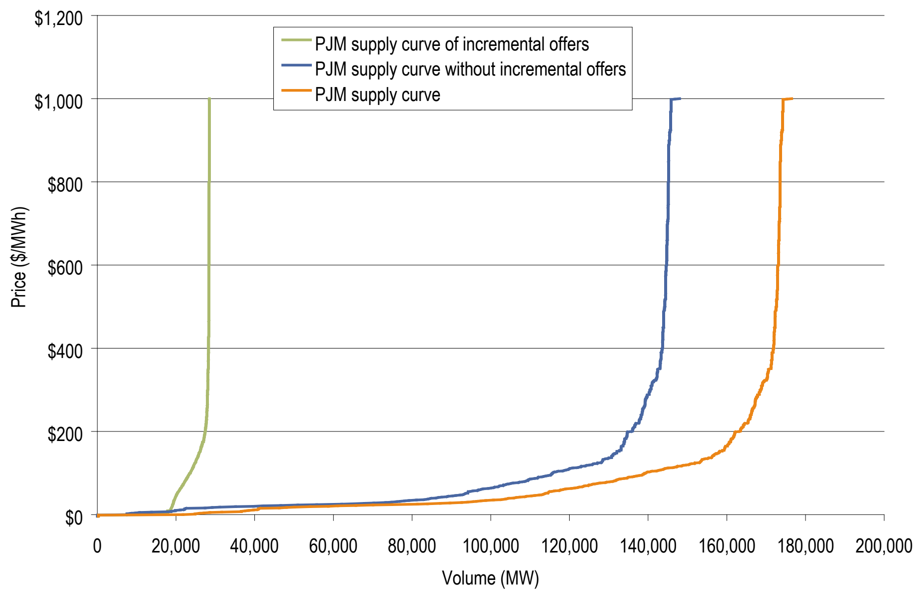
Table 2-78 Type of day-ahead marginal units: Calendar year 2007

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	16.0%	29.2%	34.2%	19.9%	0.8%
Feb	10.4%	34.9%	33.1%	20.1%	1.4%
Mar	14.3%	35.4%	33.4%	16.0%	0.9%
Apr	11.5%	31.6%	37.9%	18.3%	0.7%
May	10.8%	38.5%	30.3%	19.9%	0.5%
Jun	14.6%	22.5%	40.8%	21.7%	0.4%
Jul	13.9%	20.9%	35.4%	29.1%	0.6%
Aug	11.0%	19.0%	41.4%	27.8%	0.7%
Sep	14.9%	27.5%	36.2%	20.6%	0.8%
Oct	14.6%	24.4%	40.7%	19.9%	0.5%
Nov	16.8%	24.0%	42.2%	16.5%	0.5%
Dec	14.5%	23.1%	45.5%	16.5%	0.4%
Annual	13.6%	27.1%	37.7%	20.9%	0.7%

61 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 2-18 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 2007. There were average hourly increment offers of 28,476 MW and average hourly total offers of 176,507 MW for the example day.

Figure 2-18 PJM day-ahead aggregate supply curves: 2007 example day



PJM Price Convergence

Although the introduction of PJM Day-Ahead Energy Market and virtual offers and bids was expected to cause prices in the Day-Ahead and Real-Time Energy Markets to converge, 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 cannot occur 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 2-20.) There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis. (See Figure 2-21.)

As Table 2-79, Figure 2-19, Figure 2-20 and Figure 2-21 show, day-ahead and real-time prices were relatively close, on average, during 2007. PJM day-ahead average prices were lower than real-time prices by $2.91 per MWh during 2007. On average, day-ahead prices were lower than real-time prices by $1.17 per MWh during 2006, by $0.19 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.

Table 2-79 shows that during 2007, average LMP in the Real-Time Energy Market was $2.91 per MWh or 5.1 percent higher than average LMP in the Day-Ahead Energy Market. The real-time median LMP was 4.8 percent lower than day-ahead median LMP, reflecting an average difference of $2.42 per MWh. Price dispersion in the Real-Time Energy Market was 30.7 percent greater than in the Day-Ahead Energy Market, with an average difference in standard deviation between the two of $10.61 per MWh.

Table 2-79 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$54.67	$57.58	$2.91	5.1%
Median	$52.34	$49.92	($2.42)	(4.8%)
Standard deviation	$23.99	$34.60	$10.61	30.7%

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 2007, real-time prices were higher than day-ahead prices by more than $50 per MWh for 300 hours, more than $100 per MWh for 45 hours and more than $150 per MWh for 14 hours. In 2006, real-time prices had been higher than day-ahead prices by more than $50 per MWh for 172 hours, more than $100 per MWh for 20 hours, and more than $150 per MWh for 11 hours. If the hours with price differences greater than $150 per MWh are excluded, the difference between real-time and day-ahead price is $2.48 per MWh in 2007 rather than $2.91 and is $0.82 per MWh in 2006 rather than $1.17. Although real-time prices were higher than day-ahead prices on average in 2007, real-time prices were lower than day-ahead prices for 52.9 percent of the hours. During hours when real-time prices were higher than day-ahead prices, the average positive difference between them was $18.65 per MWh. During hours when real-time prices were less than day-ahead prices, the average negative difference was -$11.12 per MWh.

Figure 2-19 shows the 2007 PJM real-time and day-ahead price difference duration curves, with a price difference range limited to -$100 per MWh to $200 per MWh for presentation purposes. Only a few points are not shown in the figure. The PJM real-time price was lower than the day-ahead price by more than $100 per MWh for one hour in 2003, one hour in 2005 and two hours in 2006. The PJM real-time price was higher than the day-ahead price by more than $200 per MWh for seven hours in 2006 and nine hours in 2007.

Figure 2-19 PJM real-time and day-ahead price difference duration curves (-$100/MWh to $200/MWh): Calendar years 2003 to 2007

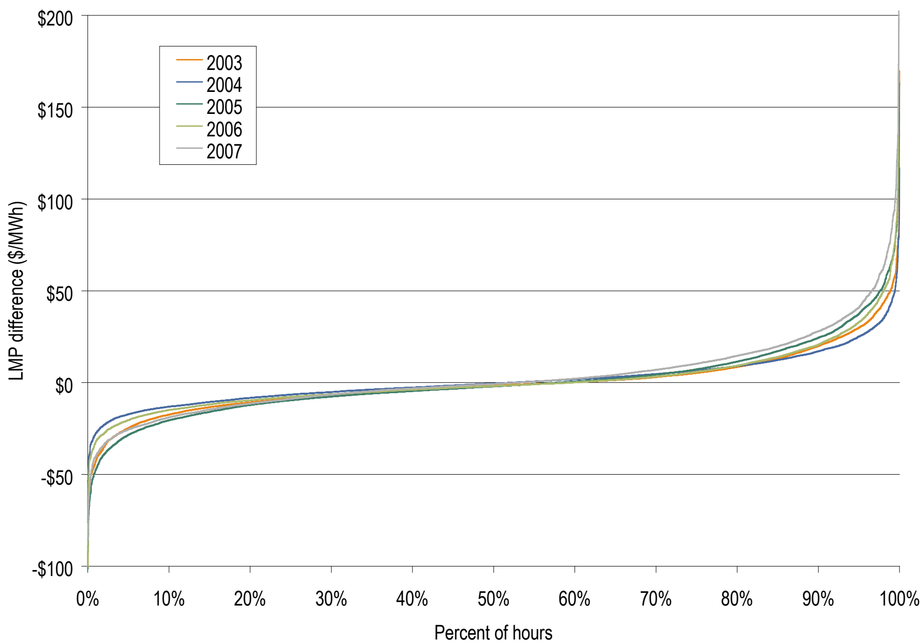


Figure 2-20 shows the hourly differences between day-ahead and real-time LMP in 2007. Although the average difference between the Day-Ahead and Real-Time Energy Market was $2.91 per MWh for the entire year, Figure 2-20 demonstrates the considerable variation, both positive and negative, between day-ahead and real-time prices. The highest difference between real-time and day-ahead LMP was $473.47 per MWh for the hour ended 1700 on August 8, 2007, when the real-time LMP was $673.98 (peak real-time LMP for 2007) and the day-ahead LMP was $200.50.

Figure 2-20 Hourly real-time minus hourly day-ahead LMP: Calendar year 2007

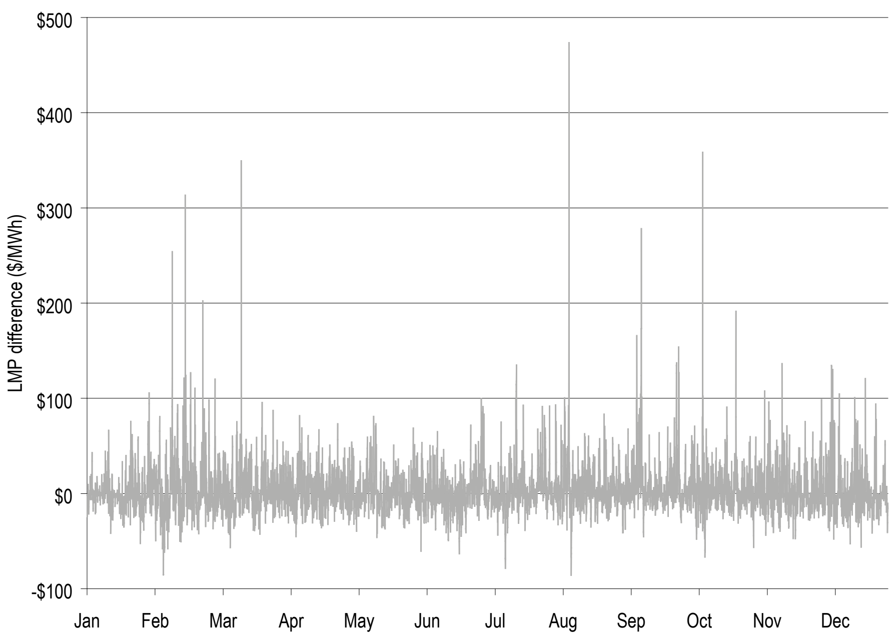
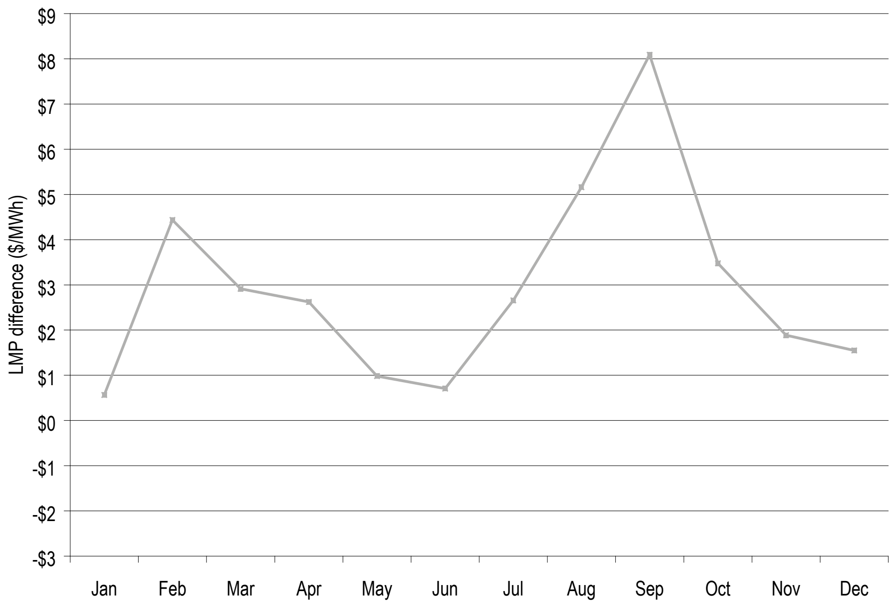


Figure 2-21 shows the monthly average differences between the day-ahead and real-time LMP in 2007. The highest monthly difference was in September. However, as Figure 2-14 shows, the coal, gas, light oil and heavy oil prices in September 2007 were 6.7 percent, 21.6 percent, 22.1 percent and 37.4 percent higher, respectively, than the corresponding fuel prices in September 2006. Further, September 2007 had 627 real-time constrained hours, an increase of 21.7 percent over the real-time constrained hours during September 2006. The day-ahead constrained hours were the same in September 2007 and September 2006.[62]

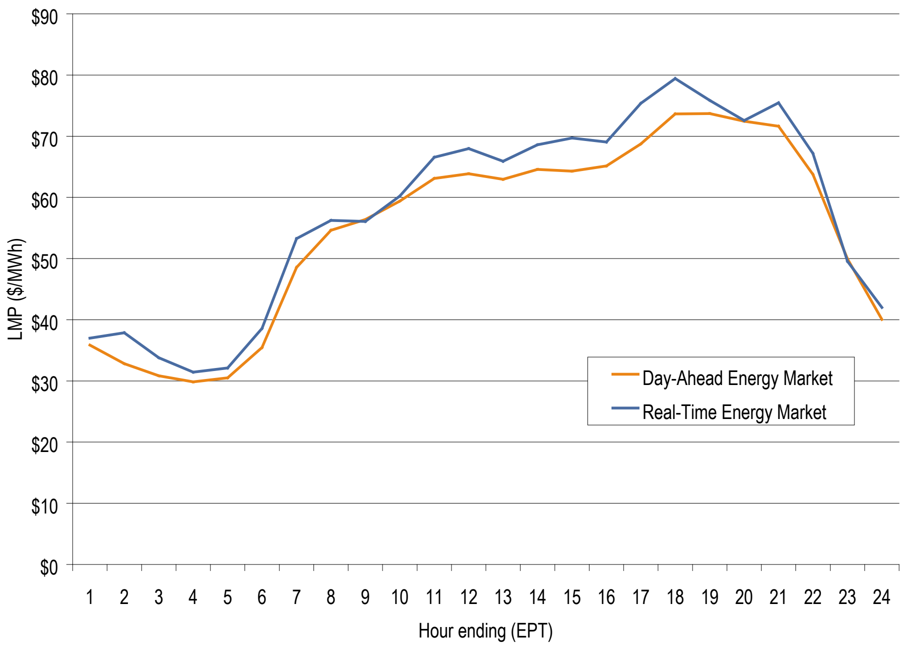
Figure 2-21 Monthly average of real-time minus day-ahead LMP: Calendar year 2007



62 For constrained hour information, see the *2007 State of the Market Report*, Volume II, Appendix C, "Energy Market.," Figure C-1, "PJM real-time constrained hours: Calendar years 2006 to 2007."

Figure 2-22 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.[63]

Figure 2-22 PJM system hourly average LMP: Calendar year 2007



63 See the *2007 State of the Market Report*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Zonal Price Convergence

Table 2-80 shows 2007 zonal day-ahead and real-time average LMP. The difference between zonal day-ahead and real-time LMP ranged from $0.18 in the DLCO Control Zone to $4.42 in the BGE Control Zone, where the day-ahead average LMP was lower than the real-time average LMP.

Table 2-80 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$62.96	$65.02	$2.06	3.2%
AEP	$45.55	$46.55	$1.00	2.1%
AP	$54.88	$57.45	$2.57	4.5%
BGE	$65.37	$69.79	$4.42	6.3%
ComEd	$45.35	$45.71	$0.36	0.8%
DAY	$45.29	$46.47	$1.18	2.5%
DLCO	$43.75	$43.93	$0.18	0.4%
Dominion	$63.42	$66.75	$3.33	5.0%
DPL	$61.95	$64.15	$2.20	3.4%
JCPL	$63.18	$65.74	$2.56	3.9%
Met-Ed	$61.62	$64.57	$2.95	4.6%
PECO	$61.25	$62.60	$1.35	2.2%
PENELEC	$52.97	$54.80	$1.83	3.3%
Pepco	$66.44	$70.33	$3.89	5.5%
PPL	$60.00	$62.02	$2.02	3.3%
PSEG	$63.94	$65.92	$1.98	3.0%
RECO	$63.37	$64.85	$1.48	2.3%

Price Convergence by Jurisdiction

Table 2-81 shows the 2007 day-ahead and real-time average LMPs by jurisdiction. The difference between day-ahead and real-time LMP ranged from $0.37 in Illinois to $3.97 in Maryland, where the day-ahead average LMP was lower than the real-time average LMP.

Table 2-81 Jurisdiction Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Delaware	$61.40	$63.45	$2.05	3.2%
Illinois	$45.34	$45.71	$0.37	0.8%
Indiana	$45.47	$46.24	$0.77	1.7%
Kentucky	$45.40	$46.52	$1.12	2.4%
Maryland	$65.64	$69.61	$3.97	5.7%
Michigan	$46.00	$46.82	$0.82	1.8%
New Jersey	$63.59	$65.78	$2.19	3.3%
North Carolina	$59.83	$62.58	$2.75	4.4%
Ohio	$44.71	$45.69	$0.98	2.1%
Pennsylvania	$56.84	$58.72	$1.88	3.2%
Tennessee	$46.52	$47.32	$0.80	1.7%
Virginia	$61.01	$63.83	$2.82	4.4%
West Virginia	$46.54	$48.39	$1.85	3.8%
District of Columbia	$66.40	$70.25	$3.85	5.5%

Load and Spot Market

Real-Time Load and Spot Market

As a general matter, 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 single PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. PJM billing organizations represent customers having billing accounts with PJM. Supply from its own generation (self-supply) means that the organization is generating power from plants that it owns at the same time that it is meeting load. Supply from bilateral purchases means that the organization is purchasing power under bilateral contracts at the same time that it is meeting load. Supply from spot market purchases means that the organization 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. Real-Time Energy Market transactions are referred to as spot market activity because they are transactions made in a short-term 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 billing organizations that serve load in the Real-Time Energy Market for each hour. Table 2-82 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2006 and 2007 based on billing organizations. For 2007, 95.9 percent of real-time load was supplied by bilateral contract, 3.9 percent by spot market purchase and 0.2 percent by self-supply. Compared with 2006, reliance on bilateral contracts increased by 3.1 percentage points; reliance on spot supply decreased by 2.3 percentage points and reliance on self-supply decreased by 0.8 percentage points in 2007.

Table 2-82 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on billing organizations: Calendar years 2006 to 2007

	2006			2007			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	92.4%	6.5%	1.0%	94.9%	4.5%	0.6%	2.5%	(2.0%)	(0.4%)
Feb	92.5%	6.5%	1.0%	95.3%	4.5%	0.1%	2.8%	(2.0%)	(0.9%)
Mar	92.6%	6.4%	1.0%	95.3%	4.5%	0.2%	2.7%	(1.9%)	(0.8%)
Apr	92.7%	6.2%	1.0%	95.3%	4.5%	0.2%	2.6%	(1.7%)	(0.8%)
May	92.7%	6.2%	1.1%	95.6%	4.2%	0.2%	2.9%	(2.0%)	(0.9%)
Jun	93.2%	5.8%	1.0%	96.1%	3.7%	0.2%	2.9%	(2.1%)	(0.8%)
Jul	93.3%	5.8%	0.9%	96.7%	3.1%	0.2%	3.4%	(2.7%)	(0.7%)
Aug	93.2%	6.0%	0.8%	96.6%	3.3%	0.2%	3.4%	(2.7%)	(0.6%)
Sep	92.8%	6.1%	1.0%	96.5%	3.4%	0.1%	3.7%	(2.7%)	(0.9%)
Oct	92.2%	6.7%	1.1%	96.2%	3.6%	0.2%	4.0%	(3.1%)	(0.9%)
Nov	92.6%	6.3%	1.1%	96.0%	3.8%	0.2%	3.4%	(2.5%)	(0.9%)
Dec	92.6%	6.4%	1.0%	95.9%	3.9%	0.2%	3.3%	(2.5%)	(0.8%)
Annual	92.8%	6.2%	1.0%	95.9%	3.9%	0.2%	3.1%	(2.3%)	(0.8%)

The relative shares of bilateral contracts, spot market transactions and self-supply to supply real-time load are also calculated by summing across all the parent companies of PJM billing organizations. Table 2-83 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2006 and 2007 based on parent company. As Table 2-83 shows, based on parent company, 22.8 percent of 2007 real-time load was supplied by bilateral contracts, 3.9 percent by spot market purchase and 73.3 percent by self-supply. Compared with Table 2-82, while the share of spot transactions is almost identical between the billing organization and parent company approaches, on average, the share of bilateral contracts was lower for parent companies and the share of self-supply was higher. This reflects the fact that, on average, while some load-serving affiliates purchased their needs bilaterally, generation affiliates of the corresponding parent also sold power under bilateral contracts in the PJM Real-Time Energy Market.

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 2006 to 2007

	2006			2007			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	19.4%	5.4%	75.2%	22.0%	3.7%	74.4%	2.6%	(1.7%)	(0.8%)
Feb	19.4%	5.1%	75.5%	22.3%	3.8%	73.9%	2.9%	(1.3%)	(1.6%)
Mar	19.9%	5.0%	75.2%	21.6%	4.0%	74.4%	1.7%	(1.0%)	(0.8%)
Apr	20.1%	4.4%	75.5%	22.4%	4.7%	72.9%	2.3%	0.3%	(2.6%)
May	19.9%	4.6%	75.5%	22.4%	3.9%	73.7%	2.5%	(0.7%)	(1.8%)
Jun	20.6%	4.7%	74.8%	22.8%	3.1%	74.0%	2.2%	(1.6%)	(0.8%)
Jul	20.5%	6.3%	73.2%	23.9%	4.3%	71.8%	3.4%	(2.0%)	(1.4%)
Aug	20.6%	5.5%	73.9%	23.8%	3.6%	72.6%	3.2%	(1.9%)	(1.3%)
Sep	20.5%	5.1%	74.4%	23.1%	3.8%	73.2%	2.6%	(1.3%)	(1.2%)
Oct	20.9%	5.5%	73.6%	23.7%	5.5%	70.8%	2.8%	0.0%	(2.8%)
Nov	20.2%	5.4%	74.4%	22.8%	4.3%	73.0%	2.6%	(1.1%)	(1.4%)
Dec	19.6%	5.2%	75.2%	22.3%	2.8%	74.9%	2.7%	(2.4%)	(0.3%)
Annual	20.1%	5.2%	74.6%	22.8%	3.9%	73.3%	2.7%	(1.3%)	(1.3%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can use not only their own generation, bilateral contracts and spot market purchases to supply their obligations as in the Real-Time Energy Market, but also can use virtual resources to meet their obligations in any hour. Participants can both buy and sell virtual resources (increment offers and decrement bids). If a participant has a positive net virtual position in an hour, it is selling energy in the Day-Ahead Energy Market. If a participant has a negative net virtual position in an hour, it is buying energy in the Day-Ahead Market.

The PJM system's reliance on self-supply, bilateral contracts, spot purchases and virtual resources to meet day-ahead load (cleared fixed-demand and price-sensitive load) is calculated by summing across all 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, spot purchases and virtual resources in 2006 and 2007, based on billing organizations. For 2007, 20.1 percent of day-ahead load was supplied by bilateral contracts, 36.0 percent by spot market purchases, 32.5 percent by self-supply and 11.3 percent by virtual resources. Compared with 2006, reliance on bilateral contracts decreased by 9.5 percentage points, reliance on spot supply increased by 3.8 percentage points, reliance on self-supply increased by 4.3 percentage points and reliance on virtual-supply increased by 1.3 percentage points in 2007.

Table 2-84 Monthly average percentage of day-ahead self-supply load, bilateral supply load, spot and virtual supply load based on billing organizations: Calendar years 2006 to 2007

	2006				2007				Difference in Percentage Points			
	Bilateral Contract	Spot	Self-Supply	Virtual	Bilateral Contract	Spot	Self-Supply	Virtual	Bilateral Contract	Spot	Self-Supply	Virtual
Jan	29.6%	31.3%	30.2%	8.9%	18.6%	36.1%	33.8%	11.5%	(11.0%)	4.8%	3.6%	2.6%
Feb	29.8%	31.5%	30.3%	8.3%	20.4%	36.7%	32.8%	10.0%	(9.4%)	5.2%	2.5%	1.7%
Mar	29.9%	31.5%	29.6%	9.0%	20.4%	35.4%	32.5%	11.7%	(9.5%)	3.9%	2.9%	2.7%
Apr	29.7%	31.5%	29.6%	9.3%	20.2%	35.3%	32.3%	12.2%	(9.5%)	3.8%	2.7%	2.9%
May	29.6%	31.4%	29.4%	9.7%	20.7%	35.1%	32.1%	12.2%	(8.9%)	3.7%	2.7%	2.5%
Jun	29.1%	32.3%	28.1%	10.5%	19.8%	36.6%	31.8%	11.7%	(9.3%)	4.3%	3.7%	1.2%
Jul	30.7%	33.4%	26.2%	9.7%	19.9%	36.7%	31.6%	11.9%	(10.8%)	3.3%	5.4%	2.2%
Aug	29.7%	33.8%	26.6%	9.9%	19.0%	36.4%	33.0%	11.6%	(10.7%)	2.6%	6.4%	1.7%
Sep	29.2%	32.2%	27.2%	11.4%	20.1%	36.2%	32.4%	11.3%	(9.1%)	4.0%	5.2%	(0.1%)
Oct	29.1%	32.0%	27.5%	11.4%	20.2%	36.0%	31.9%	11.8%	(8.9%)	4.0%	4.4%	0.4%
Nov	29.5%	31.7%	27.6%	11.2%	21.1%	35.2%	32.7%	11.0%	(8.4%)	3.5%	5.1%	(0.2%)
Dec	28.9%	33.1%	27.1%	10.9%	21.4%	36.5%	32.8%	9.3%	(7.5%)	3.4%	5.7%	(1.6%)
Annual	29.6%	32.2%	28.2%	10.0%	20.1%	36.0%	32.5%	11.3%	(9.5%)	3.8%	4.3%	1.3%

The relative shares of bilateral contracts, spot market transactions, self-supply and virtual resources to meet day-ahead load (cleared fixed-demand and price-sensitive load) are also calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. As Table 2-85 shows, based on parent companies, 5.3 percent of day-ahead load was supplied by bilateral contracts, 14.9 percent by spot market purchases, 67.4 percent by self-supply and 12.3 percent by virtual-supply for 2007. Compared with Table 2-84, while the share of spot transactions and the share of bilateral contracts were lower for parent companies, the share of self-supply was higher. This reflects the fact that, on average, while some load-serving affiliates purchased some of their needs bilaterally, generation affiliates of the corresponding parent also sold power under bilateral contracts in the PJM Day-Ahead Energy Market. The reduction, on average, in the reliance on spot transactions by parent companies reflects the fact that some parent companies have both spot sales and spot purchases and that the spot purchases are more concentrated in the load-serving affiliates.

Table 2-85 Monthly average percentage of day-ahead self-supply load, bilateral supply load, spot and virtual supply load based on parent companies: Calendar years 2006 to 2007

	2006				2007				Difference in Percentage Points			
	Bilateral Contract	Spot	Self-Supply	Virtual	Bilateral Contract	Spot	Self-Supply	Virtual	Bilateral Contract	Spot	Self-Supply	Virtual
Jan	3.2%	8.0%	79.0%	9.8%	4.6%	13.9%	68.8%	12.6%	1.4%	5.9%	(10.2%)	2.8%
Feb	3.4%	8.4%	78.8%	9.4%	4.8%	13.6%	69.0%	12.6%	1.4%	5.2%	(9.8%)	3.2%
Mar	3.7%	8.8%	77.6%	9.9%	5.0%	14.0%	67.9%	13.1%	1.3%	5.2%	(9.7%)	3.2%
Apr	3.7%	7.9%	78.5%	10.0%	5.2%	13.8%	67.8%	13.2%	1.5%	5.9%	(10.7%)	3.2%
May	3.9%	9.3%	77.0%	9.7%	6.0%	13.0%	67.5%	13.4%	2.1%	3.7%	(9.5%)	3.7%
Jun	4.0%	9.2%	75.8%	11.0%	5.3%	15.0%	67.0%	12.6%	1.3%	5.8%	(8.8%)	1.6%
Jul	4.4%	9.8%	75.1%	10.7%	5.2%	16.0%	66.3%	12.5%	0.8%	6.2%	(8.8%)	1.8%
Aug	4.5%	9.1%	75.5%	11.0%	4.9%	15.5%	67.7%	12.0%	0.4%	6.4%	(7.8%)	1.0%
Sep	5.1%	9.3%	74.0%	11.5%	5.6%	15.9%	66.9%	11.5%	0.5%	6.6%	(7.1%)	0.0%
Oct	5.2%	10.1%	73.5%	11.2%	5.7%	17.0%	65.0%	12.3%	0.5%	6.9%	(8.5%)	1.1%
Nov	4.8%	9.2%	74.2%	11.8%	6.0%	15.8%	66.8%	11.4%	1.2%	6.6%	(7.4%)	(0.4%)
Dec	4.7%	9.2%	74.0%	12.1%	6.1%	15.6%	68.2%	10.1%	1.4%	6.4%	(5.8%)	(2.0%)
Annual	4.2%	9.0%	76.0%	10.7%	5.3%	14.9%	67.4%	12.3%	1.1%	5.9%	(8.6%)	1.6%

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.[64] The goal of the program should be neither 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.

64 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.

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).[65] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[66] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007.[67] 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.[68, 69] 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.[70] 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."[71, 72] 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 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, the Economic Program represents a minimal and relatively efficient intervention into the market.

On February 14, 2002, the PJM Members Committee approved a permanent Emergency Load-Response Program.[73] 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).[74] 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.[75] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[76] 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.[77]

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

66 99 FERC ¶ 61,227 (2002).

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

68 114 FERC ¶ 61,201 (February 24, 2006).

69 Analysis of the role of demand-side resources in the Ancillary Service Markets can be found in the *2007 State of the Market Report*, Volume II, Section 6, "Ancillary Service Markets," at "Synchronized Reserve Market."

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

71 121 FERC ¶ 61,315 (December 31, 2007) at ¶ 26.

72 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.pjm.com/markets/market-monitor/downloads/20071204-dsr-whitepaper.pdf> (118.4 KB).

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

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

75 99 FERC ¶ 61,139 (2002).

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

77 114 FERC ¶ 61,201 (February 24, 2006).

As of 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.[78]

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.[79] Customers offering resources into an RPM Auction are paid the resource-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.

The LM program is comprised of two types of resources: ILR resources and demand resources (DR). 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.[80] The Emergency-Energy Only option is voluntary; customers who 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.

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 August 8, 2007, the peak-load day for the year, there were 9.25 MW of available resources in the Emergency-Energy Only option of the Emergency Program.[81] There was no activity under this option in calendar year 2007.

Table 2-86 also shows the zonal distribution of DSR capability in the Emergency-Full option and in the Emergency-Capacity option of the Emergency Program on August 8, 2007. The BGE Control Zone included 20 percent of all registered sites and 23 percent of all registered MW under the Emergency-Full option. The ComEd Control Zone included 61 percent of all registered sites and 37 percent of all registered MW in the capacity option of the Emergency Program.

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

79 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.

80 "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.

81 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): August 8, 2007

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	2	2.00	25	3.70	3	3.10
AEP	0	0.00	12	437.60	9	118.40
AP	0	0.00	4	45.30	6	63.60
BGE	2	7.25	40	234.70	12	21.60
ComEd	0	0.00	6	64.80	306	409.80
DAY	0	0.00	0	0.00	0	0.00
DLCO	0	0.00	0	0.00	2	2.30
Dominion	0	0.00	0	0.00	3	10.90
DPL	0	0.00	14	54.10	5	4.40
JCPL	0	0.00	8	6.70	6	49.70
Met-Ed	0	0.00	7	8.80	13	33.20
PECO	0	0.00	28	77.30	63	110.20
PENELEC	0	0.00	2	1.50	1	0.00
Pepco	0	0.00	6	9.00	4	19.30
PPL	0	0.00	16	9.30	62	236.40
PSEG	0	0.00	34	88.70	8	20.90
RECO	0	0.00	0	0.00	0	0.00
Total	4	9.25	202	1,041.50	503	1,103.80

In 2007, there was one day with emergency activity, August 8, 2007, the day of the system's annual peak. The period of compliance for the Emergency Program occurred between the hours ending 1500 EPT and 1800 EPT in the Mid-Atlantic and Southern regions.[82] Zonal real-time, load-weighted, average LMPs were between $208.81 per MW and $1,059.13 per MW during the emergency activity within the Mid-Atlantic and Southern regions. The Emergency Program reductions on August 8, 2007, occurred during and after the scarcity pricing event that was triggered for certain scarcity pricing zones within the Mid-Atlantic and Southern regions.[83]

Table 2-87 shows the overcompliance and undercompliance of resources in the Emergency Program by ILR and DR resources on August 8, 2007, within the zones where the emergency event was called. Altogether, ILR resources overcomplied by 7.6 MW and DR resources overcomplied by 15.4 MW during the emergency activity.

82 Compliance hours are defined as a full hour during the emergency event. For example, if event started in 1530 and is over at 1720, only the hour between 1600 and 1700 (i.e., hour ending 17) will be counted as a compliance hour by PJM.

83 For a complete discussion of the August 8, 2007, scarcity pricing events, see the *2007 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," "2007 High-Load Events, Scarcity and Scarcity Pricing Events."

Table 2-87 Zonal overcompliance and undercompliance of ILR and DR capacity resources (MW): August 8, 2007

	Committed UCAP		Over / (Under)compliance		Actual Reduction	
	DR	ILR	DR	ILR	DR	ILR
AECO	0.00	6.90	0.00	1.50	0.00	8.40
BGE	14.70	249.30	3.00	1.70	17.70	251.00
Dominion	0.00	11.30	0.00	2.90	0.00	14.20
DPL	5.10	27.40	0.30	1.10	5.40	28.50
JCPL	0.00	9.80	0.00	1.30	0.00	11.10
Met-Ed	1.20	36.50	(0.70)	2.90	0.50	39.40
PECO	12.30	101.40	(0.20)	(27.30)	12.10	74.10
PENELEC	0.00	1.50	0.00	2.20	0.00	3.70
Pepco	5.00	23.90	13.00	7.30	18.00	31.20
PPL	0.00	252.30	0.00	13.00	0.00	265.30
PSEG	0.00	106.40	0.00	1.00	0.00	107.40
Total	38.30	826.70	15.40	7.60	53.70	834.30

Table 2-88 shows the zonal, Emergency-Full option, energy MWh participation levels and associated payments during the emergency activity of August 8, 2007.[84] In total $878,828 credits were paid for 1,005 MWh that responded during the emergency hours.[85]

Table 2-88 Zonal Emergency-Full option energy payments and MWh participation: August 8, 2007

	MWh	Payments
AECO	8.4	$8,517
BGE	130.9	$131,380
DPL	227.3	$201,897
JCPL	31.8	$31,903
Met-Ed	9.7	$9,193
PECO	75.1	$75,427
PENELEC	13.7	$11,182
Pepco	129.5	$130,672
PPL	17.2	$17,205
PSEG	361.7	$261,451
Total	1,005.2	$878,828

84 Energy MWh and payments for each zone are calculated for hours of emergency activity rather than for the compliance hours of the emergency. Hours of emergency activity may include lead times prior to the emergency event for each zone.

85 The hourly energy payment for the Emergency-Full option is equal to the sum of the customer's shutdown cost (once per day) and the product of the MWh reduction and the greater of zonal load-weighted LMP or customer submitted strike price. Strike price is the LMP specified by a customer at which load shall be reduced.

Table 2-89 shows zonal monthly capacity credits that were paid during the June 1, 2007, through December 31, 2007, period to ILR and DR resources. The total amount of the credits was $34,454,412.[86] November credits include credits and charges for overcompliance and undercompliance by ILR and DR resources on August 8, 2007.

Table 2-89 Zonal monthly capacity credits: June 1, 2007, through December 31, 2007

	June	July	August	September	October	November	December
AECO	$36,745	$37,969	$37,969	$36,745	$37,969	$44,712	$37,969
AEP	$147,247	$152,155	$152,155	$147,247	$152,155	$147,247	$152,155
AP	$137,700	$142,290	$142,290	$137,700	$142,290	$137,700	$142,290
BGE	$1,131,403	$1,169,116	$1,169,116	$1,131,403	$1,169,116	$1,164,145	$1,169,116
COMED	$598,781	$618,740	$618,740	$598,781	$618,740	$598,781	$618,740
DAY	$2,448	$2,530	$2,530	$2,448	$2,530	$2,448	$2,530
Dominion	$13,831	$14,292	$14,292	$13,831	$14,292	$22,492	$14,292
DPL	$338,049	$349,317	$349,317	$338,049	$349,317	$343,714	$349,317
DLCO	$2,815	$2,909	$2,909	$2,815	$2,909	$2,815	$2,909
JCPL	$308,867	$319,163	$319,163	$308,867	$319,163	$319,246	$319,163
Met-Ed	$53,366	$55,145	$55,145	$53,366	$55,145	$57,846	$55,145
PECO	$1,033,625	$1,068,079	$1,068,079	$1,033,625	$1,068,079	$660,645	$1,068,079
PENELEC	$1,836	$1,897	$1,897	$1,836	$1,897	$7,809	$1,897
Pepco	$128,776	$133,068	$133,068	$128,776	$133,068	$289,702	$133,068
PPL	$309,917	$320,247	$320,247	$309,917	$320,247	$348,742	$320,247
PSEG	$600,694	$620,717	$620,717	$600,694	$620,717	$583,626	$620,717
RECO	$0	$0	$0	$0	$0	$0	$0
Total	$4,846,099	$5,007,636	$5,007,636	$4,846,099	$5,007,636	$4,731,670	$5,007,636

Economic Program

On August 8, 2007, there were 2,498.03 MW registered in the Economic Program compared to the 1,100.65 MW on August 2, 2006, an increase of 127 percent. (See Table 2-90.)

Table 2-90 Economic Program registration: Within 2002 to 2007

	Sites	Peak-Day, Registered MWh
14-Aug-02	96	335.40
22-Aug-03	240	650.56
03-Aug-04	782	875.56
26-Jul-05	2,548	2,210.18
02-Aug-06	253	1,100.65
08-Aug-07	2,897	2,498.03

86 Since ILR and DR resources are paid capacity credits on a daily basis, monthly zonal capacity credits are equal for months with the same number of days. The level of ILR and DR MW that are paid capacity credits was established in the RPM for the period from June 2007 to May 2008.

Table 2-91 shows the zonal distribution of capability in the Economic Program on August 8, 2007. The ComEd Control Zone includes 76 percent of sites and 27 percent of registered MW in the Economic Program.

Table 2-91 Zonal capability in the Economic Program: August 8, 2007

	Sites	MW
AECO	23	19.86
AEP	2	121.00
AP	27	231.05
BGE	152	393.75
ComEd	2,193	667.32
DAY	1	3.50
DLCO	6	64.70
Dominion	26	191.80
DPL	95	126.46
JCPL	36	57.40
Met-Ed	17	52.77
PECO	121	175.28
PENELEC	10	47.15
Pepco	6	14.05
PPL	53	200.53
PSEG	127	130.82
RECO	2	0.60
Total	2,897	2,498.03

The total MWh of load reduction and the associated payments under the Economic Program are shown in Table 2-92.[87] Load reduction levels increased to 608,745 MWh in calendar year 2007.[88] Payments per MWh were $74 in 2007. The Economic Program's actual load reduction per peak-day, registered MW rose to 243.7 MWh for calendar year 2007, an increase of 3.8 percent from 2006.[89]

In the calendar year 2007, the maximum hourly load reduction attributable to the Economic Program was 1,032 MW on August 2.

87 The "Total MWh" and "Total Payments" shown in Table 2-92 for calendar year 2005 are different from those reported in the MMU report, "Assessment of PJM Load-Response Program" filed on August 29, 2006, with the FERC, as a result of settlement adjustments made since that time. The "Total MWh" and "Total Payments" for both the Economic and the Emergency Programs shown here are also subject to subsequent settlement adjustments in 2008.

88 The Economic Program payments and MWh presented in this report do not include all settlement adjustments for 2006 and 2007. The data are provided by PJM's DSR department; Economic Program payments and MWh reductions are based on the January 2008, PJM billing information and are subject to adjustments.

89 The "Total MWh" and "Total Payments" for calendar year 2006 are different from those reported in the *2006 State of the Market Report,* as a result of settled disputes. The "Total MWh" increased by 11,472 MWh and the "Total Payments" increased by $1,217,695.

Table 2-92 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	608,745	$45,173,237	$74	243.7

In 2007, Economic Program participants in the PECO Control Zone accounted for 42 percent of all real-time reductions and received 32 percent of all real-time payments. (See Table 2-93.) The total number of curtailed hours for the Economic Program was 208,227 and the total payment amount was $45,173,237.[90]

Overall, approximately 92 percent of the MWh reductions, 89 percent of payments and 92 percent of curtailed hours resulted from the real-time option under the Economic Program.[91] Approximately 5 percent of the MWh reductions, 6 percent of payments and 2 percent of curtailed hours resulted from the day-ahead option.[92] Approximately 3 percent of the MWh reductions, 5 percent of the payments and 7 percent of the curtailed hours resulted from the dispatched-in-real-time option of the program. (See Table 2-93.)

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

91 "Real-Time" reductions are self-scheduled reductions and "Dispatched in Real-Time" reductions that are dispatched by PJM in real-time.

92 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 2-93 PJM Economic Program by zonal reduction: Calendar year 2007

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	250	$18,530	802	0	($7)	3	267	$9,604	339	516	$28,126	1,144
AEP	1,969	$84,867	192	0	$0	0	0	$0	0	1,969	$84,867	192
AP	63,172	$4,199,874	15,177	0	($1,042)	9	690	$73,167	1,037	63,861	$4,272,000	16,223
BGE	56,652	$7,787,520	11,822	0	$0	0	6,374	$908,321	130	63,025	$8,695,840	11,952
ComEd	32,275	$1,416,493	14,723	990	$43,015	1,283	3,510	$258,964	2,226	36,775	$1,718,472	18,232
DAY	0	$0	0	47	$4,225	48	8	$603	3	55	$4,827	51
DLCO	954	$60,654	1,060	0	$0	0	36	$2,295	18	989	$62,949	1,078
Dominion	36,433	$3,807,981	8,790	0	$0	0	585	$68,499	1,343	37,018	$3,876,480	10,133
DPL	8,311	$877,016	6,156	6,503	$831,535	645	42	$8,604	3	14,857	$1,717,155	6,804
JCPL	241	$9,582	448	12,506	$1,379,116	346	44	$4,901	64	12,791	$1,393,599	858
Met-Ed	3,043	$246,723	1,329	218	$43,959	46	176	$14,553	1,244	3,438	$305,235	2,619
PECO	236,562	$13,030,066	107,528	9,346	$475,566	652	3,845	$521,428	5,021	249,753	$14,027,060	113,201
PENELEC	128	$6,017	397	5	$923	4	172	$10,836	285	305	$17,775	686
Pepco	35,750	$3,430,294	3,218	0	$0	0	164	$10,200	601	35,914	$3,440,494	3,819
PPL	81,780	$4,979,800	12,946	1,000	$65,911	219	186	$24,951	475	82,967	$5,070,663	13,640
PSEG	2,781	$253,052	6,280	335	$57,575	47	1,352	$143,659	1,103	4,469	$454,286	7,430
RECO	41	$3,258	156	1	$150	9	0	$0	0	43	$3,408	165
Total	560,343	$40,211,728	191,024	30,952	$2,900,924	3,311	17,449	$2,060,585	13,892	608,745	$45,173,237	208,227
Max	236,562	$13,030,066	107,528	12,506	$1,379,116	1,283	6,374	$908,321	5,021	249,753	$14,027,060	113,201
Avg	32,961	$2,365,396	11,237	1,821	$170,643	195	1,026	$121,211	817	35,809	$2,657,249	12,249

The Economic Load-Response Program in 2007 provided for larger payments when LMP was greater than, or equal to, $75 per MWh. This additional payment is termed a subsidy or incentive payment. About 43 percent of all MWh reductions, 47 percent of all curtailed hours and 12 percent of all Economic Program payments occurred when LMP was less than $75 per MWh. Table 2-94 shows that reductions under the Economic Program when zonal, load-weighted, average LMP was less than $75 per MWh were dispersed over all hours of the day, with somewhat lower levels of activity in the hours ended 0100 EPT through 0600 EPT and the hour ended 2400 EPT.

Table 2-94 Frequency distribution of Economic Program hours when zonal, load-weighted, average LMP less than $75 MWh (By hours): Calendar year 2007

Hour	Frequency	Percent	Cumulative Frequency	Cumulative Percent
1	1,651	1.69%	1,651	1.69%
2	1,890	1.93%	3,541	3.61%
3	1,936	1.98%	5,477	5.59%
4	2,777	2.83%	8,254	8.42%
5	3,045	3.11%	11,299	11.53%
6	3,594	3.67%	14,893	15.20%
7	4,040	4.12%	18,933	19.32%
8	4,633	4.73%	23,566	24.05%
9	5,203	5.31%	28,769	29.36%
10	5,868	5.99%	34,637	35.35%
11	5,478	5.59%	40,115	40.94%
12	5,275	5.38%	45,390	46.33%
13	5,579	5.69%	50,969	52.02%
14	5,421	5.53%	56,390	57.55%
15	4,866	4.97%	61,256	62.52%
16	4,762	4.86%	66,018	67.38%
17	4,559	4.65%	70,577	72.03%
18	4,038	4.12%	74,615	76.16%
19	4,572	4.67%	79,187	80.82%
20	4,693	4.79%	83,880	85.61%
21	3,972	4.05%	87,852	89.67%
22	3,936	4.02%	91,788	93.68%
23	3,596	3.67%	95,384	97.35%
24	2,592	2.65%	97,976	100.00%

Table 2-95 shows that reductions under the Economic Program when zonal, load-weighted, average LMP was greater than, or equal to, $75 per MWh were generally higher in hours ended 1100 EPT through 2200 EPT, with the highest levels of activity in hours ended 1200 EPT through 2000 EPT.

Table 2-95 Frequency distribution of Economic Program hours with zonal, load-weighted, average LMP greater than, or equal to, $75 per MWh (By hours): Calendar year 2007

Hour	Frequency	Percent	Cumulative Frequency	Cumulative Percent
1	228	0.21%	228	0.21%
2	346	0.31%	574	0.52%
3	265	0.24%	839	0.76%
4	225	0.20%	1,064	0.97%
5	260	0.24%	1,324	1.20%
6	835	0.76%	2,159	1.96%
7	2,947	2.67%	5,106	4.63%
8	3,140	2.85%	8,246	7.48%
9	3,542	3.21%	11,788	10.69%
10	3,998	3.63%	15,786	14.32%
11	6,253	5.67%	22,039	19.99%
12	7,215	6.54%	29,254	26.53%
13	7,590	6.88%	36,844	33.42%
14	8,431	7.65%	45,275	41.07%
15	9,199	8.34%	54,474	49.41%
16	8,786	7.97%	63,260	57.38%
17	9,382	8.51%	72,642	65.89%
18	9,796	8.89%	82,438	74.77%
19	7,866	7.13%	90,304	81.91%
20	6,707	6.08%	97,011	87.99%
21	6,328	5.74%	103,339	93.73%
22	4,633	4.20%	107,972	97.93%
23	1,433	1.30%	109,405	99.23%
24	846	0.77%	110,251	100.00%

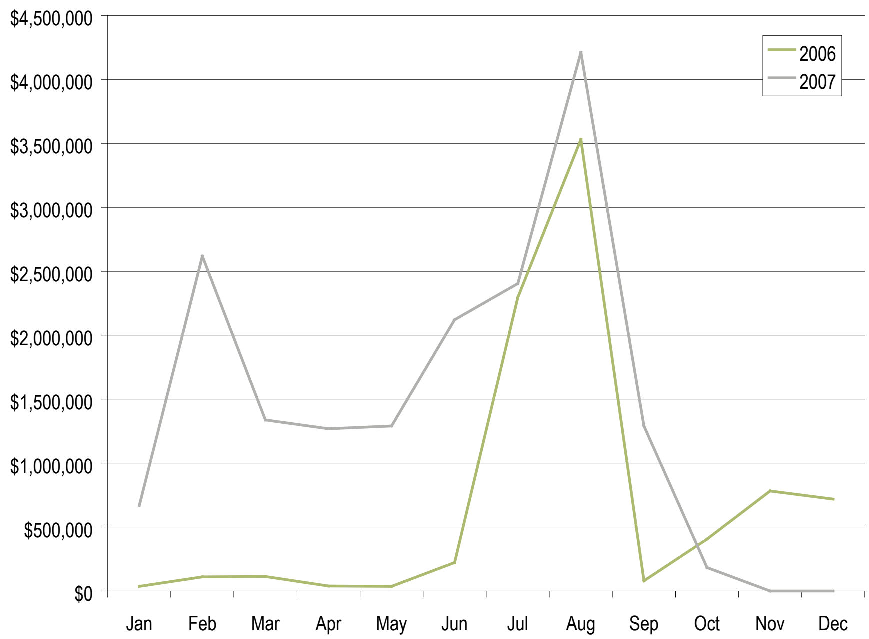
Table 2-96 shows the frequency distribution of Economic Program hourly reductions by real-time zonal, load-weighted, average LMP in price ranges of $15 per MWh. Activity occurred primarily when zonal, load-weighted, average LMP was between $15 and $135 per MWh. Most hours, 52.95 percent, during which reductions took place had zonal, load-weighted, average LMP greater than, or equal to, $75 per MWh.

Table 2-96 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2007

LMP ($/MWh)	Frequency	Percent	Cumulative Frequency	Cumulative Percent
$0 to $15	12	0.01%	12	0.01%
$15 to $30	9,182	4.41%	9,194	4.42%
$30 to $45	22,368	10.74%	31,562	15.16%
$45 to $60	29,329	14.09%	60,891	29.24%
$60 to $75	37,085	17.81%	97,976	47.05%
$75 to $90	39,978	19.20%	137,954	66.25%
$90 to $105	26,655	12.80%	164,609	79.05%
$105 to $120	14,575	7.00%	179,184	86.05%
$120 to $135	8,999	4.32%	188,183	90.37%
$135 to $150	5,821	2.80%	194,004	93.17%
$150 to $165	3,998	1.92%	198,002	95.09%
$165 to $180	2,412	1.16%	200,414	96.25%
$180 to $195	1,786	0.86%	202,200	97.11%
$195 to $210	1,207	0.58%	203,407	97.69%
$210 to $225	1,070	0.51%	204,477	98.20%
$225 to $240	843	0.40%	205,320	98.60%
$240 to $255	667	0.32%	205,987	98.92%
$255 to $270	349	0.17%	206,336	99.09%
$270 to $285	213	0.10%	206,549	99.19%
$285 to $300	189	0.09%	206,738	99.28%
$300 to $315	171	0.08%	206,909	99.37%
$315 to $330	244	0.12%	207,153	99.48%
$330 to $345	116	0.06%	207,269	99.54%
$345 to $360	65	0.03%	207,334	99.57%
$360 to $375	71	0.03%	207,405	99.61%
$375 to $390	89	0.04%	207,494	99.65%
$390 to $405	19	0.01%	207,513	99.66%
$405 to $420	69	0.03%	207,582	99.69%
$420 to $435	19	0.01%	207,601	99.70%
$435 to $450	77	0.04%	207,678	99.74%
$450 to $465	41	0.02%	207,719	99.76%
$465 to $480	71	0.03%	207,790	99.79%
$480 to $495	153	0.07%	207,943	99.86%
$495 to $510	41	0.02%	207,984	99.88%
$510 to $525	2	0.00%	207,986	99.88%
$525 to $540	4	0.00%	207,990	99.89%
> $540	237	0.11%	208,227	100.00%

Figure 2-23 shows the monthly distribution of incentive payments for calendar years 2006 and 2007.[93] In 2007, substantial increases in incentive payments occurred throughout the year. Incentive payments reached a monthly maximum in August in both 2007 and 2006. On October 24, 2007, PJM issued the statement that the demand-side resources incentive cap of $17.5 had been reached.[94] PJM allocated $17 million of incentive payments and $500,000 was reserved for disputed settlements. 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.[95]

Figure 2-23 Incentive payments: Calendar years 2006 and 2007



93 When LMP is greater than, or equal to, $75 per MWh, customers are 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), is charged to all LSEs in the zone of the load reduction. If the total amount of recoverable charges reflecting the generation and transmission payments for the entire program exceeds $17.5 million in a year, participants will receive LMP less an amount equal to the applicable generation and transmission charges for the remainder of the year, regardless of the level of LMP. The incentive payments are included in Economic Program payments.

94 Letter from S. Covino to the PJM Members <http://www.pjm.com/committees/working-groups/dsrwg/postings/incentive-cap-reached.pdf> (9.58 KB).

95 Incentive payments for 2006 and 2007 for this report were confirmed by PJM's DSR department. These payments are subject to monthly settlement adjustments. The incentive payments for 2006 and 2007 are based on the January 2008, PJM billing information.

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

Table 2-97 shows the available ALM MW for 2002 to 2006 and the available LM MW for 2007.

Table 2-97 Available ALM MW and LM MW: Within 2002 to 2007

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

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. In the 2006 and 2007 state of the market reports, real-time hourly supply curves were developed for summer hours 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. PJM hourly supply curves for the period from June to September 2007 were analyzed.

The analysis showed that a reduction of 1 MW resulted in a price reduction of between $0.0015 and $0.0016 per MW.

Measurement Issues

Customer Base Line (CBL)

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 lead to 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. 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.

Under current DSR business rules, participants in the Economic Program can measure their reductions by comparing metered load against an estimate of what metered load would have been absent the reduction.[96] CBL calculations were intended to estimate “A set of days that will serve as representative of a retail

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

customer's typical usage."[97] Separate calculations are done for weekdays and weekends/holidays and customers can use weather sensitivity factors to adjust the CBL calculations, if desired.

The current weekday CBL methodology requires the selection of 10 weekdays and the five highest are used for the calculation. However, 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. There is currently no limit on the historical period that can be used to select the 10 days, called the CBL basis window. The high threshold for low usage days (75 percent) combined with no limitation on the historical period for the basis window can result in an inflated estimate of what metered load would have been absent the reduction.

Another issue with the existing measurement and verification rules is that there is no clear requirement that a customer had to take a verifiable step to reduce energy use in response to prices in order to receive payment under the program. This omission allows retail customers to submit activities like maintenance outages, equipment failures, storm outages, scheduled vacation shutdowns or plant closures as load reductions and receive payments. The DSR business rules should clearly define load curtailments and should exclude such activities from the CBL window calculations.

The electricity distribution company (EDC) or LSE is responsible for reviewing a customer's CBL data and may object to the calculations. When an EDC or LSE objects, customers have time to resubmit the data, which are also subject to review. In 2006, there were multiple settlement disputes in which an EDC or LSE did not approve CBL calculations, and customers requested PJM involvement.

The Customer Base Line Subcommittee was created 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."[98]

In December 2007, proposals to modify CBL business rules were presented to the Market Implementation Committee with focus on two major issues: the permissible period for selecting a comparable day and number of days to be used for the CBL calculation and the definition of a demand-side curtailment.

Accurate measurement and verification is essential to ensuring that the Economic Program achieves its objectives and achieves its goal of paying for actual resource savings rather than paying for phantom savings. Any measurement and verification protocol based on broad average usage levels will be inaccurate at least part of the time. That is why, when a payment is contested, PJM and the MMU must have the explicit authority to apply more detailed measurement techniques to verify claimed usage reductions and to ensure that no payments are made in the absence of verifiable reductions.

97 OA, Original Sheet No. 119A, Effective February 24, 2006.

98 "Customer Baseline Committee Charter," February 27, 2007, <http://www.pjm.com/ committees/subcommittee/cbls/postings/20070223-final-charter.pdf> (22.7 KB).