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 Market, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Market. 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 2006, including market size, concentration, residual supply index, price-cost markup, net revenue and prices. The MMU concludes that the PJM Energy Market results were competitive in 2006.

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.[1] 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.

Analysis of 2006 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM integrated five new control zones. When making comparisons to 2004 and 2005, the *2006 State of the Market Report* refers to three phases in calendar year 2004 and two phases in 2005 that correspond to those integrations.[2]

Overview

Market Structure

- **Supply.** During the June to September 2006 summer period, the PJM Energy Market received an hourly average of 155,600 MW in net supply, including hydroelectric generation, excluding real-time imports or exports. The summer 2006 net supply was 1,160 MW higher than the summer 2005 net supply. The increase was comprised of 400 MW of increased hydroelectric power generation and a 760 MW increase in net capacity in the regional transmission organization (RTO) footprint.

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

2 For additional information on PJM's footprint and the definition of these phases, see *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

- **Demand.** The PJM system peak load in 2006 was 144,644 MW in the hour ended 1700 EPT on August 2, 2006, while the PJM peak load in 2005 was 133,763 in the hour ended 1600 on July 26, 2005.[3] The 2006 peak load was 10,881 MW, or 8.1 percent, higher than the 2005 peak load and therefore intersected the supply curve at a higher price level than would have occurred with a lower level of demand.

- **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. PJM offer caps units only when their owners would otherwise exercise local market power. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM and generally declined in 2006.

- **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 2006. 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 2006, the top four companies accounted for 49 percent of the load-weighted, system average locational marginal price (LMP).

  In 2006, coal-fired units accounted for 70 percent of marginal units and natural gas-fired units accounted for 25 percent of all marginal units.

3 For the purpose of Volume I and Volume II of the *2006 State of the Market Report*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix K, "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. 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 0.00 with a monthly average maximum of 0.05 in February and a monthly average minimum of -0.02 in August. The markup at times substantially exceeded these levels and was at times below these levels but the overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or very 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 explicitly captured in the conduct markup measure. The MMU has added explicit measures of the price component of marginal unit markups. The markup component of the overall system load-weighted, average locational marginal price (LMP) was $1.54 per MWh, or 2.9 percent. The markup was $3.08 per MWh during peak hours and -$0.10 per MWh during off-peak hours. The markup component of price at times substantially exceeded these levels and was at times below these levels, but the overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or very close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

  A substantial portion of the markup, $0.60 per MWh or 39 percent occurred on high-load days during the summer of 2006. 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 $0.56 per MWh, or 36 percent, of the markup for all days. This is a disproportionate share, given that only 43 of 56 exempt units were marginal and that only eight exempt units of the 43 accounted for $0.50, or 90 percent, of this markup component of price. The average markup per exempt unit is about nine times higher than for non-exempt units, and the average markup for the top eight exempt units is about 43 times higher than for non-exempt units.

- **Load.** On average, PJM real-time load increased in 2006 by 1.7 percent over 2005, but this increase reflected the fact that the first four months of 2006 included Dominion load which was not present in the four months of 2005. The 2006 PJM real-time average load, calculated to be directly comparable to 2005 by excluding the 2006 load resulting from the integration of Dominion for the first four months, was lower than in 2005 by about 2.5 percent.

- **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 decreased in 2006. The simple average system LMP was 15.2 percent lower in 2006 than in 2005, $49.27 per MWh versus $58.08 per MWh. The load-weighted LMP was 15.9 percent lower in 2006 than in 2005, $53.35 per MWh versus $63.46 per MWh. The fuel-cost-adjusted, load-weighted, average LMP was 5.6 percent lower in 2006 than in 2005, $59.89 per MWh compared to $63.46 per MWh.

Demand-Side Response

- **Demand-Side Response (DSR).** Markets require both a supply side and a demand side to function effectively. The demand side of the wholesale energy market is underdeveloped for a variety of complex reasons. Total demand-side response resources available in PJM on August 2, 2006 (the peak day in 2006), were 3,511 MW of which 1,679 MW were from active load management, 1,081 MW from the Emergency Load-Response Program and 1,101 MW from the Economic Load-Response Program. There were 350 MW enrolled in both the Load-Response Program and in active load management. When additional demand-side resources as of June 1, 2006, reported by PJM customers in response to a survey, are included, there were 6,703 MW in total DSR resources in the summer of 2006, 4.6 percent of PJM's peak demand. Including the PJM Economic Program and survey responses, there were 2,597 MW of load directly exposed to LMP in 2006, or 1.8 percent of peak load.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance for calendar year 2006, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply increased by about 1,160 MW when comparing the summer of 2006 to the summer of 2005 while aggregate peak load increased by 10,881 MW, modifying the general supply-demand balance from 2005 with a corresponding impact on peak energy market prices. Overall load was lower than in 2005, when measured on a comparable footprint basis, with a corresponding moderating impact on overall average prices. Market concentration levels remained moderate and average markups remained low. 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. 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. 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.

PJM introduced a new test for structural market power in 2006, the three pivotal supplier test. 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 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. The result of the introduction of the three pivotal supplier test was to limit offer capping to situations when the local market structure was noncompetitive and where 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.[4] 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 non-discriminatory basis for all units operating for all constraints.

The MMU recommends that the FERC terminate the exemption from offer capping currently applicable to certain units, if those units exercise local market power. 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 found "that the exemption for post-1996 units from the offer capping rules is unjust and unreasonable under

4 See PJM OA, Sections 6.4.1(d)(ii) and 6.4.1(e) (January 19, 2007).

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."[5] 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."[6] A small number of exempt units accounted for a disproportionate share of markup in 2006. Eight exempt units accounted for 33 percent of the overall markup component of prices in 2006.

Energy Market results, including prices, for 2006 generally reflected supply-demand fundamentals. Lower nominal and load-weighted prices are consistent with a competitive outcome as the lower prices reflect both lower input fuel costs and lower overall demand. If fuel costs for the year 2006 had been the same as for 2005, the 2006 load-weighted LMP would have been higher than it was, $59.89 per MWh instead of $53.35 per MWh. Fuel-cost reductions were a substantial part (64.7 percent) of the reason for lower LMP in 2006, but prices would have been lower in the absence of the lower fuel costs. The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at or very close to their marginal costs. This is strong 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 2006.

Market Structure

Supply

During the June to September 2006 summer period, the PJM Energy Market received an hourly average of 155,600 MW in net supply including hydroelectric generation, excluding real-time imports or exports.[7] The summer 2006 net supply was 1,160 MW higher than the summer 2005 net supply. The increase was comprised of 400 MW of increased hydroelectric power generation and a 760 MW increase in net capacity in the RTO footprint. During the summer of 2006, the peak demand was 10,880 MW, or 8.1 percent, higher than the 2005 peak and therefore intersected the supply curve at a higher price level. (See Figure 2-1.)[8]

Offer prices on the 2006 supply curve are lower than on the 2005 supply curve from total supply levels of about 90,000 MW to 140,000 MW, corresponding to 2006 offers from about $45 per MWh to about $225 per MWh. This range of offers consists primarily of natural gas-fired steam, combined-cycle (CC) and efficient combustion turbine (CT) units. Approximately 80 percent of all gas-fired generation falls in this portion of the offer curve. The decrease in the offer curve is largely the result of lower natural gas prices for summer 2006 compared to summer 2005. The average delivered price of natural gas decreased from $9.85 per MBtu for summer 2005 to $6.75 per MBtu for summer 2006, or 31 percent. Between about 135,000 MW and 150,000 MW the 2006 supply curve is above, but parallel to the 2005 supply curve, meaning that incremental offers and MW are comparable between the two years while, in aggregate, the

5 110 FERC ¶ 61,053 (2005).

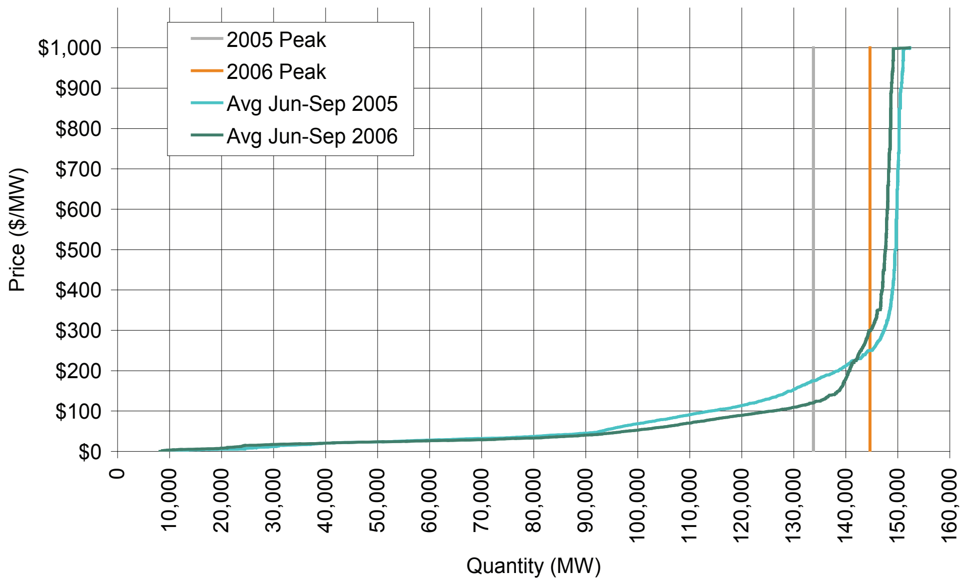
6 110 FERC ¶ 61,053 (2005).

7 The method used to compile the aggregate energy market supply curve has been improved. The aggregate supply curve for 2005 now includes about 14,200 fewer MW than in the *2005 State of the Market Report*. Approximately 3,700 MW of units that are external to the PJM Control Area and are not available for PJM dispatch have been removed from the supply curve and are accounted for as transactions when MWh are supplied. Approximately 1,200 MW of mothballed generation were removed from the curve. Approximately 9,300 MW were removed from the supply curve as these MW were not available in the hourly bid economic maxima.

8 All figures in this paragraph have been rounded to the nearest 10 MW.

2006 supply curve is shifted to the left by approximately 1,900 MW. This shift is the result of a decrease of approximately 1,900 MW in offers of $998 per MWh to $1,000 per MWh. The total 2006 offers in the $998 to $1,000 per MWh range are about 3,100 MW.

Figure 2-1 Average PJM aggregate supply curves: Summers 2005 and 2006



During the 12 months ended September 30, 2006, 1,830 MW of generation entered service in the RTO.[9] The additions consisted of 1,690 MW in upgrades to existing generation and 140 MW in new generation. After accounting for offsetting decreases of 1,070 MW from the derating of 440 MW of generation, 100 MW removed from RTO dispatch to behind the meter service and the retirement of 530 MW, the net increase in capacity was 760 MW. Upgrades to existing facilities included 150 MW of combustion turbine generation, 1,320 MW of combined-cycle generation, 30 MW of coal-fired steam, 40 MW of gas/oil-fired steam, 10 MW of nuclear steam, 20 MW of wind generation, 10 MW of diesel generation and 110 MW of hydroelectric generation. Of the 140 MW of new generation, 90 MW were combustion turbine generation, 20 MW were wind generation and 30 MW were diesel generation.

Of the 440 MW of derated generation, 240 MW were combustion turbine generation, 80 MW were combined-cycle generation and 120 MW were gas/oil-fired steam. Of the 100 MW of generation removed from PJM dispatch, 50 MW were combined-cycle generation and 50 MW were diesel generation. Of the 530 MW of retirements, 60 MW were combustion turbine generation, 210 MW were combined-cycle generation, 230 MW were coal-fired steam, 20 MW were gas/oil-fired steam and 10 MW were diesel generation.[10]

The net result of generation additions and subtractions, holding other factors constant, was a slight shift to the right of the PJM aggregate supply curve as a high proportion (72 percent) of additional generation was

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

10 All figures in this discussion have been rounded to the nearest 10 MW.

intermediate combined-cycle units and a similarly high proportion (72 percent) of the retirements and downgrades was of less efficient, more costly peaking generation including CTs, oil and gas-fired steam and diesels. The shape of the aggregate supply curve changed only slightly since the net increase of generation was less than 1 percent of the system supply. Table 2-1 shows the PJM units that retired from October 1, 2005, to September 30, 2006.[11]

Table 2-1 Retired units: October 1, 2005, to September 30, 2006

Unit Name	Installed Capacity (MW)	Retire Date
PS Newark Boxboard	52	11-Oct-05
AEP Conesville 1	115	01-Jan-06
AEP Conesville 2	115	01-Jan-06
PS Marcal Paper	47	09-Jan-06
PEP Gude Landfill	2	25-Mar-06
JC Parlin	114	10-Apr-06
PS Bayonne 1	21	20-May-06
PS Bayonne 2	21	20-May-06
PS Linden 3	21	24-May-06
AE Vineland 9	17	01-Jun-06
Total	525	

Demand

Table 2-2 shows the actual coincident summer peak loads for the years 1999 through 2006.[12] The 2006 actual summer peak load of 144,644 MW was 10,881 MW more than the 2005 summer peak load of 133,763 MW. Peak loads reflect the increasing size of the PJM Control Area.[13]

Table 2-2 Actual PJM footprint summer peak loads: 1999 to 2006

Year	Date	EPT Hour Ending	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

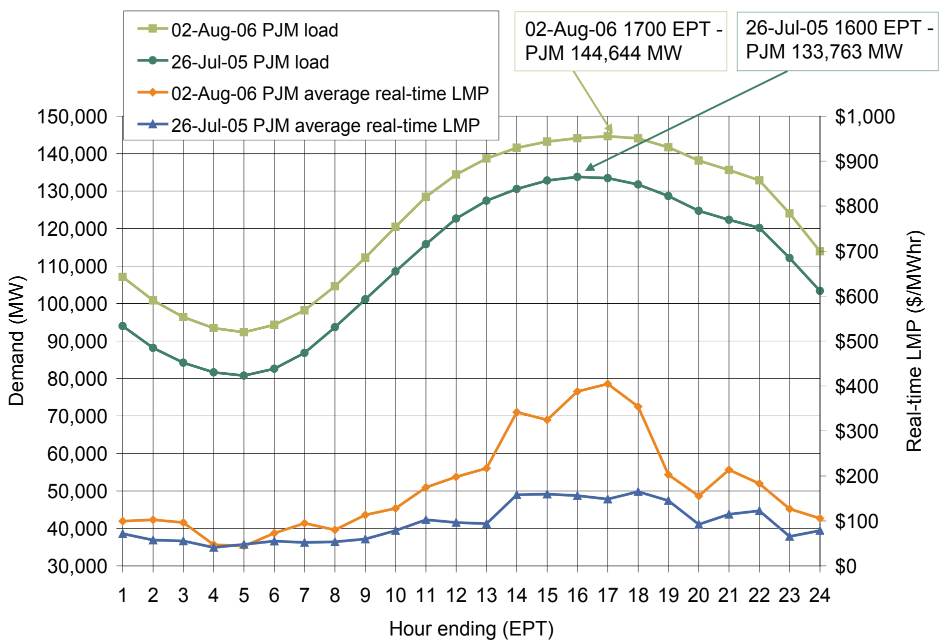
11 Retired unit parameters obtained from PJM.

12 Peak loads shown have been obtained from the electricity distribution companies (EDCs) and represent the actual loads after all monthly meter reconciliations have been completed.

13 See *2006 State of the Market Report,* Volume II, Appendix A, "PJM Geography" for a description of the 2004 and 2005 integrations.

The hourly load and average PJM LMP for the 2005 and 2006 summer peak days are shown in Figure 2-2.

Figure 2-2 PJM summer peak-load comparison: Wednesday, August 2, 2006, and Tuesday, July 26, 2005



Market Concentration

During 2006, 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.[14] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power and generation owners' obligations to serve load were effective in most cases in preventing the exercise of market power in these areas during 2006. 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 2006.

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.

14 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.

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.[15]

15 77 FERC ¶ 61,263, "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 2006 was moderately concentrated. (See Table 2-3.) Based on the hourly energy market measure, average HHI was 1256 with a minimum of 865 and a maximum of 1620 in 2006. The highest hourly market share was 30 percent and the highest average market share for 2006 was 21 percent.

Table 2-3 PJM hourly energy market HHI: Calendar year 2006

	Hourly Market HHI
Average	1256
Minimum	865
Maximum	1620
Highest Market Share (One Hour)	30%
Highest Market Share (All Hours)	21%
# Hours	8,760
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

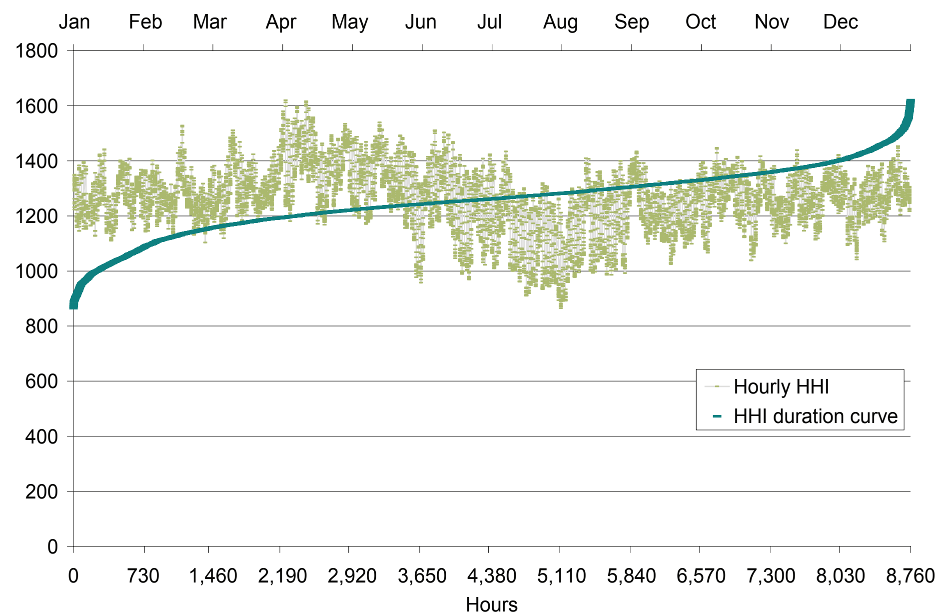
Table 2-4 includes 2006 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

Table 2-4 PJM hourly energy market HHI (By segment): Calendar year 2006

	Minimum	Average	Maximum
Base	1232	1390	1684
Intermediate	683	2664	6868
Peak	732	4157	10000

Figure 2-3 presents the 2006 hourly HHI values in chronological order and an HHI duration curve that shows 2006 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 3 percent of the hours while HHI values were in the moderately concentrated range in the remaining 97 percent of hours, with a maximum value of 1620, as shown in Table 2-3.

Figure 2-3 PJM hourly energy market HHI: Calendar year 2006



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 Market. 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.[16] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules 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.

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

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's market power tests in real time.[17] 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 2002 to 2006

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2002	1.6%	0.3%	0.7%	0.1%
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%

In order to help understand the frequency of offer capping in more detail, Table 2-6 presents data on the frequency with which units were offer capped in 2006. Table 2-6 shows the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for 2006.18 For example, in 2006 four units were offer capped for more than 80 percent of their run hours and had at least 500 offer-capped run hours. The count of units in each category includes units that also met more restrictive criteria. In this example, the four units that were offer capped during more than 80 percent of their run hours and had a total of at least 500 offer-capped run hours are also included in the 80 percent row for the 400 offer-capped, run-hour column as well as the 300 offer-capped, run-hour column and the one offer-capped, run-hour column. The one offer-capped, run-hour column shows the total number of units meeting each percentage threshold with any offer-capped hours for the year. Similarly in this example, the four units that were offer capped for more than 80 percent of their run hours are also included in each of the subsequent rows corresponding to a specific column, as they were also offer capped during more than 75 percent, 60 percent, 50 percent, 25 percent and 10 percent of their run hours.

17 See *2006 State of the Market Report*, Volume II, Appendix J, "Three Pivotal Supplier Test."

18 Details on prior years are shown in the *2006 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 2006

Percentage of Offer-Capped Run Hours	2006 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	3	3	3	4	6	6
80%	4	9	10	15	20	25
75%	4	10	11	18	29	46
70%	4	10	11	20	37	72
60%	4	11	13	25	47	108
50%	4	13	15	27	49	122
25%	4	15	18	32	55	158
10%	4	15	18	35	67	212

Table 2-6 shows that a very 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 15 units (or about 1 percent of all units) were offer capped for more than 80 percent of their run hours and had offer-capped run hours of 200 hours or more. Only 27 units (or about 2 percent of all units) were offer capped for more than 50 percent of their run hours and had offer-capped run hours of 200 hours or more. Only 35 units (about 3 percent of all units) that had offer-capped run hours of at least 200 hours (about 2 percent of all hours) in 2006 were offer capped for 10 percent or more of their run hours.

Table 2-6 shows a substantial decrease in the number of units in most offer-capping categories when compared to 2005. All categories of units with more than 300 offer-capped hours decreased by more than 50 percent, all categories of units with more than 200 offer-capped hours decreased by at least 47 percent and all categories of units with more than 100 offer-capped hours decreased by at least 37 percent. The only categories showing increases were units offer capped for fewer than 100 hours and for 50 percent and 60 percent of run hours where the increase was 6 percent in both cases.

In addition, all units that are offer capped for more than 60 percent of their run hours, frequently mitigated units (FMUs), or units that are associated with FMUs (AUs) are entitled to receive adders to their costs that are a form of local scarcity pricing.

Local Market Structure

In 2006, the PSEG, AP, AEP, Met-Ed, PECO, PENELEC, Dominion, DPL and AECO Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using results from PJM's March 1, 2006, implementation of the three pivotal supplier test in real time, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[19] The ComEd, BGE, DLCO, JCPL, PPL, RECO, PEPCO and DAY Control Zones were not affected by constraints binding for 100 or more hours.

19 See *2006 State of the Market Report,* Volume II, Appendix J, "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 March 1, 2006, through December 31, 2006.

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 64 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 one or 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 $160 million in day-ahead and $6 million in balancing congestion costs during 2006. The exempt interfaces were constrained for more hours in the Day-Ahead Market than in the Real-Time Market. During 2006, the exempt interfaces were constrained 2,643 hours in the Day-Ahead Market and 591 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.

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.

- **Regional 500 kV Constraints.** In 2006, several regional transmission constraints occurred for more than 100 hours. The Kammer 765/500 kV transformer, along with four interface constraints, 5004/5005, AP South, Bedington-Black Oak and West all experienced more than 100 hours of congestion.[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 79 percent to 88 percent while 25 percent to 34 percent of the tests showed 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 64 percent to 99 percent while 3 percent to 55 percent of the tests showed one or more owners failing.

Table 2-7 Three pivotal supplier results summary for regional constraints: March 1, to December 31, 2006

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	863	705	82%	253	29%
	Off Peak	209	183	88%	53	25%
Bedington - Black Oak	Peak	2,622	2,072	79%	889	34%
	Off Peak	3,254	2,708	83%	980	30%
Kammer	Peak	627	520	83%	194	31%
	Off Peak	925	763	82%	302	33%
AP South	Peak	491	327	67%	229	47%
	Off Peak	180	116	64%	99	55%
West	Peak	852	846	99%	28	3%
	Off Peak	566	541	96%	47	8%

Table 2-8 shows that, on average, during 2006 peak periods, the local markets created by the 5004/5005 Interface and the Kammer transformer had 17 owners with available supply during the peak period. Of those owners, an average of 14 passed the test for the 5004/5005 Interface and an average of 13 passed the test for the Kammer transformer.[23] Bedington-Black Oak, on average, had 12 owners with available supply and nine owners passed the test. For AP South, on average, nine out of 15 owners passed the test during off-peak periods, and 10 out of 16 owners passed during on-peak periods. For the West Interface, on average, 15 out of 16 owners passed the test during off-peak periods, and all 17 owners passed the test during on-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: March 1, to December 31, 2006

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	110	397	17	14	3
	Off Peak	107	376	17	14	3
Bedington - Black Oak	Peak	57	220	12	9	3
	Off Peak	63	239	12	9	2
Kammer	Peak	83	285	17	13	4
	Off Peak	77	301	15	12	3
AP South	Peak	101	271	16	10	6
	Off Peak	97	306	15	9	6
West	Peak	138	829	17	17	0
	Off Peak	140	739	16	15	1

- **East Interface and Central Interface.** The remaining two exempt interfaces, the East and Central Interfaces occurred for fewer than 100 hours. The East Interface constraint occurred for 11 hours in 2006, while the Central Interface constraint occurred for 15 hours in 2006. Table 2-9 shows that the percentage of tested intervals resulting in one or more owners passing ranged from 60 percent to 100 percent while 25 percent to 40 percent of the tests showed one or more owners failing during peak periods and no owners failing during off-peak periods.

Table 2-9 Three pivotal supplier results summary for the East and Central Interfaces: March 1, to December 31, 2006

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	16	13	81%	4	25%
	Off Peak	10	10	100%	0	0%
East	Peak	20	12	60%	8	40%
	Off Peak	NA	NA	NA	NA	NA

Table 2-10 shows that, on average, the local market created by the East Interface had 14 owners during peak periods and 11 passed the test. The East Interface did not occur during off-peak periods in 2006. The local market created by the Central Interface had 18 owners during off-peak periods and 14 passed the test. All owners passed the test for the Central Interface during on-peak periods.

Table 2-10 Three pivotal supplier test details for the East and Central Interfaces: March 1, to December 31, 2006

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	150	1,017	20	20	0
	Off Peak	177	722	18	14	4
East	Peak	209	703	14	11	3
	Off Peak	NA	NA	NA	NA	NA

- **PSEG Control Zone Constraints.** In 2006, seven 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 five of the seven 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 pass is significant only for the two constraints with more than four owners on average. The Cedar Grove-Roseland 230 kV line and the Cedar Grove-Clifton 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: March 1, to December 31, 2006

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Bergen - Hoboken	Peak	84	0	0%	84	100%
	Off Peak	62	0	0%	62	100%
Branchburg - Flagtown	Peak	496	30	6%	474	96%
	Off Peak	39	1	3%	39	100%
Branchburg - Readington	Peak	1,166	95	8%	1,102	95%
	Off Peak	280	16	6%	276	99%
Brunswick - Edison	Peak	524	0	0%	524	100%
	Off Peak	129	0	0%	129	100%
Cedar Grove - Clifton	Peak	1,083	308	28%	844	78%
	Off Peak	597	73	12%	571	96%
Cedar Grove - Roseland	Peak	1,214	484	40%	803	66%
	Off Peak	853	440	52%	474	56%
Edison - Meadow Rd	Peak	1,466	0	0%	1,466	100%
	Off Peak	207	0	0%	207	100%

Table 2-12 Three pivotal supplier test details for constraints located in the PSEG Control Zone: March 1, to December 31, 2006

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bergen - Hoboken	Peak	17	60	1	0	1
	Off Peak	20	57	1	0	1
Branchburg - Flagtown	Peak	35	35	4	1	4
	Off Peak	35	28	3	0	3
Branchburg - Readington	Peak	30	67	4	1	4
	Off Peak	20	73	3	0	3
Brunswick - Edison	Peak	10	108	1	0	1
	Off Peak	11	82	1	0	1
Cedar Grove - Clifton	Peak	34	122	8	3	5
	Off Peak	32	119	6	1	6
Cedar Grove - Roseland	Peak	57	191	11	6	5
	Off Peak	67	244	12	8	4
Edison - Meadow Rd	Peak	8	55	1	0	1
	Off Peak	7	55	1	0	1

- **AP Control Zone Constraints.** In 2006, there were eight 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 five of the eight constraints, the average number of owners with available supply was seven or less. The three pivotal supplier test results reflect this, as the average number of owners that pass 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: March 1, to December 31, 2006

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
Aqueduct - Doubs	Peak	255	46	18%	241	95%
	Off Peak	127	10	8%	124	98%
Bedington	Peak	2,978	1	0%	2,978	100%
	Off Peak	933	0	0%	933	100%
Elrama - Mitchell	Peak	117	9	8%	111	95%
	Off Peak	244	19	8%	232	95%
Meadow Brook	Peak	2,859	0	0%	2,859	100%
	Off Peak	359	0	0%	359	100%
Mitchell - Shepler Hill	Peak	420	0	0%	420	100%
	Off Peak	447	0	0%	447	100%
Mount Storm - Pruntytown	Peak	538	447	83%	155	29%
	Off Peak	1,206	938	78%	479	40%
Sammis - Wylie Ridge	Peak	140	85	61%	71	51%
	Off Peak	403	323	80%	146	36%
Wylie Ridge	Peak	1,520	1,239	82%	511	34%
	Off Peak	2,542	1,940	76%	1,004	39%

Table 2-14 Three pivotal supplier test details for constraints located in the AP Control Zone: March 1, to December 31, 2006

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Aqueduct - Doubs	Peak	22	43	5	1	5
	Off Peak	25	36	4	0	4
Bedington	Peak	42	3	2	0	2
	Off Peak	31	5	2	0	2
Elrama - Mitchell	Peak	36	103	7	1	6
	Off Peak	28	79	5	1	5
Meadow Brook	Peak	47	1	1	0	1
	Off Peak	19	2	1	0	1
Mitchell - Shepler Hill	Peak	7	13	2	0	2
	Off Peak	8	12	2	0	2
Mount Storm - Pruntytown	Peak	122	423	13	10	2
	Off Peak	126	380	11	8	3
Sammis - Wylie Ridge	Peak	56	113	15	9	6
	Off Peak	45	124	15	11	4
Wylie Ridge	Peak	45	230	16	12	4
	Off Peak	44	232	14	10	4

- **AEP Control Zone Constraints.** In 2006, there were seven 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 five of the seven 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 pass is significant only for the two constraints with a larger number of owners on average. Two constraints, the Cloverdale-Lexington 500 kV line and Kanawha-Matt Funk, 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: March 1, to December 31, 2006

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
Avon	Peak	586	0	0%	586	100%
	Off Peak	699	0	0%	699	100%
Cloverdale - Lexington	Peak	671	390	58%	395	59%
	Off Peak	4,257	2,647	62%	2,479	58%
Darwin - Eugene	Peak	385	0	0%	385	100%
	Off Peak	27	0	0%	27	100%
Kammer - Natrium	Peak	595	0	0%	595	100%
	Off Peak	699	0	0%	699	100%
Kanawha - Matt Funk	Peak	440	110	25%	396	90%
	Off Peak	1,735	552	32%	1,458	84%
Mahans Lane - Tidd	Peak	698	0	0%	698	100%
	Off Peak	40	0	0%	40	100%
Sporn	Peak	707	0	0%	707	100%
	Off Peak	78	0	0%	78	100%

Table 2-16 Three pivotal supplier test details for constraints located in the AEP Control Zone: March 1, to December 31, 2006

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Avon	Peak	20	6	2	0	2
	Off Peak	13	7	2	0	2
Cloverdale - Lexington	Peak	114	319	16	8	8
	Off Peak	99	263	14	7	6
Darwin - Eugene	Peak	27	74	2	0	2
	Off Peak	15	68	1	0	1
Kammer - Natrium	Peak	6	32	2	0	2
	Off Peak	6	34	2	0	2
Kanawha - Matt Funk	Peak	60	113	11	2	9
	Off Peak	50	106	9	2	7
Mahans Lane - Tidd	Peak	15	7	1	0	1
	Off Peak	19	10	1	0	1
Sporn	Peak	9	4	1	0	1
	Off Peak	17	8	1	0	1

- **Met-Ed Control Zone Constraints.** In 2006, the Gardners-Hunterstown 230 kV line was the only constraint to occur 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 this constraint in the Met-Ed Control Zone. The average number of owners with available supply was two on peak and one off peak. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-17 Three pivotal supplier results summary for constraints located in the Met-Ed Control Zone: March 1, to December 31, 2006

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
Gardners - Hunterstown	Peak	589	0	0%	589	100%
	Off Peak	29	0	0%	29	100%

Table 2-18 Three pivotal supplier test details for constraints located in the Met-Ed Control Zone: March 1, to December 31, 2006

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Gardners - Hunterstown	Peak	11	9	2	0	2
	Off Peak	7	23	1	0	1

- **PECO Control Zone Constraints.** In 2006, the Whitpain 500/230 kV transformer was the only constraint in the PECO 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 six on peak and five off peak. The three pivotal supplier test results reflect this, as 29 percent of the tests applied on peak and 3 percent of the tests applied off peak resulted in one or more owners passing the test.

Table 2-19 Three pivotal supplier results summary for constraints located in the PECO Control Zone: March 1, to December 31, 2006

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
Whitpain	Peak	205	59	29%	177	86%
	Off Peak	332	11	3%	331	100%

Table 2-20 Three pivotal supplier test details for constraints located in the PECO Control Zone: March 1, to December 31, 2006

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Whitpain	Peak	24	48	6	1	5
	Off Peak	35	25	5	0	5

- **PENELEC Control Zone Constraints.** In 2006, the Blairsville East transformer was the only constraint to occur 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 Blairsville East transformer. The average number of owners with available supply was three on peak and three off peak. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-21 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: March 1, to December 31, 2006

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
Blairsville East	Peak	305	2	1%	303	99%
	Off Peak	173	6	3%	169	98%

Table 2-22 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: March 1, to December 31, 2006

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Blairsville East	Peak	12	34	3	0	3
	Off Peak	15	33	3	0	2

- **Dominion Control Zone Constraints.** In 2006, 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 Halifax-Mount Laurel lines and four on peak and three off peak for the Dooms transformer constraint. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-23 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: March 1, to December 31, 2006

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	1,107	0	0%	1,107	100%
	Off Peak	182	0	0%	182	100%
Dooms	Peak	643	5	1%	643	100%
	Off Peak	67	1	1%	67	100%
Halifax - Mount Laurel	Peak	676	0	0%	676	100%
	Off Peak	346	0	0%	346	100%

Table 2-24 Three pivotal supplier test details for constraints located in the Dominion Control Zone: March 1, to December 31, 2006

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	7	6	1	0	1
Dooms	Peak	67	67	4	0	4
	Off Peak	45	58	3	0	3
Halifax - Mount Laurel	Peak	9	3	1	0	1
	Off Peak	7	3	1	0	1

- **DPL Control Zone Constraints.** In 2006, two lines in the DPL Control Zone were constrained for more than 100 hours. Table 2-25 and Table 2-26 show the results of the three pivotal supplier test applied to the constraints in the DPL 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 2-25 Three pivotal supplier results summary for constraints located in the DPL Control Zone: March 1, to December 31, 2006

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
Kings Creek - West Over	Peak	21	0	0%	21	100%
	Off Peak	NA	NA	NA	NA	NA
Mardela - Vienna	Peak	94	0	0%	94	100%
	Off Peak	31	0	0%	31	100%

Table 2-26 Three pivotal supplier test details for constraints located in the DPL Control Zone: March 1, to December 31, 2006

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Kings Creek - West Over	Peak	1	9	1	0	1
	Off Peak	NA	NA	NA	NA	NA
Mardela - Vienna	Peak	5	45	1	0	1
	Off Peak	3	58	1	0	1

- **AECO Control Zone Constraints.** In 2006, two lines in the AECO Control Zone experienced more than 100 hours of congestion. 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: March 1, to December 31, 2006

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
Carlls Corner - Sherman Ave	Peak	50	0	0%	50	100%
	Off Peak	8	0	0%	8	100%
Laurel - Woodstown	Peak	1,283	0	0%	1,283	100%
	Off Peak	563	0	0%	563	100%

Table 2-28 Three pivotal supplier test details for constraints located in the AECO Control Zone: March 1, to December 31, 2006

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Carlls Corner - Sherman Ave	Peak	3	7	1	0	1
	Off Peak	4	19	1	0	1
Laurel - Woodstown	Peak	2	6	1	0	1
	Off Peak	2	7	1	0	1

Characteristics of Marginal Units

Ownership of Marginal Units

Table 2-29 shows the contribution to system average LMP by individual generation owners, utilizing 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 the offers of one company contribute 16 percent of the annual average PJM system price and that the offers of the top four companies contribute 49 percent of the annual load-weighted, average PJM system price. There were 39 companies with individual contributions under 4 percent and a combined contribution of 24 percent.

24 See *2006 State of the Market Report*, Volume II, Appendix I, "Sensitivity Factors."

Table 2-29 Marginal unit contribution to LMP by company: Calendar year 2006

Company	Percent of Price
Company 1	16%
Company 2	13%
Company 3	10%
Company 4	10%
Company 5	7%
Company 6	7%
Company 7	5%
Company 8	4%
Company 9	4%
Other (39 Companies)	24%

Marginal Unit Fuel

Table 2-30 shows the type of fuel used by marginal units.[25] In 2006, coal-fired units accounted for 70 percent of marginal units and natural gas-fired units accounted for 25 percent of all marginal units.[26]

Table 2-30 Type of fuel used by marginal units: Calendar years 2004 to 2006

Fuel Type	2004	2005	2006
Coal	60%	69%	70%
Misc	0%	1%	1%
Natural Gas	32%	23%	25%
Nuclear	0%	0%	0%
Petroleum	9%	8%	4%

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, there are two units on the margin; one is a coal unit, the other 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 2006 is defined in the *2006 State of the Market Report*, Volume II, Section 2, Energy Market, Part 1, at "Components of Real-Time LMP," Table 2-50, "Components of annual PJM load-weighted, average LMP."

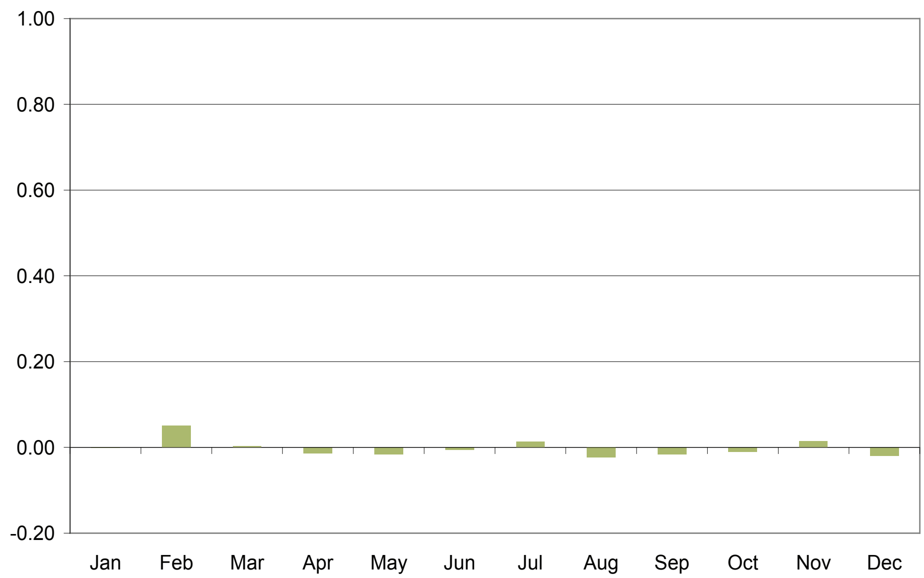
Market Conduct

Unit Markup

The price-cost markup index is a measure of conduct or behavior by the owners of generating units. 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 performance).

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 is similar to the markup index calculations presented in prior state of the market reports, but the calculation method has been improved to more accurately weight the impact of individual unit markups through use of sensitivity factors.[29] 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 year 2006



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 *2006 State of the Market Report*, Volume II, Appendix I, "Sensitivity 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 2-31 shows the average annual unit markup for marginal units, by unit type and primary fuel.

Table 2-31 Average marginal unit markup index by primary fuel and type of unit: Calendar year 2006

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	(0.01)	$1.03
Heavy Oil	Steam	0.01	$2.53
Hydroelectric	Hydroelectric	0.00	$0.00
Light Oil	CT	0.05	$13.26
Light Oil	Diesel	(0.01)	($1.38)
Misc	Misc	(0.01)	($7.14)
Natural Gas	CC	0.01	$3.48
Natural Gas	CT	0.02	$10.19
Natural Gas	Diesel	0.37	$73.50
Natural Gas	Steam	0.01	$17.45
Nuclear	Steam	0.12	$1.78

Table 2-32 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 2-32 Average marginal unit markup index by price category: Calendar year 2006

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.13)	($3.37)
$25 to $50	(0.02)	($1.38)
$50 to $75	0.01	($2.37)
$75 to $100	0.02	($0.87)
$100 to $125	0.06	$4.95
$125 to $150	0.04	$4.61
> $150	0.10	$34.56

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 has added explicit measures of the price component of marginal unit price-cost markup, based on analysis using sensitivity factors. These measures include the system price component of markup on system prices and the zonal price component of markup. In addition, the price component of specific subsets of units 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. Such a 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 costs and actual dispatch. It is possible that the 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. It is also possible that the markup, based on a redispatch analysis, would be higher than the markup component of price if the reference point were a unit, dispatched only under the redispatch, with a higher price and a lower cost than the actual marginal unit.

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 2-33 shows the markup component of average monthly on-peak, off-peak and average prices. In 2006, $1.54 per MWh of the PJM load-weighted LMP was attributable to markup. In 2006, the markup component of LMP was -$0.10 per MWh off peak and $3.08 per MWh on peak. Of the on-peak markup component, $1.15 per MWh, or 37 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]

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

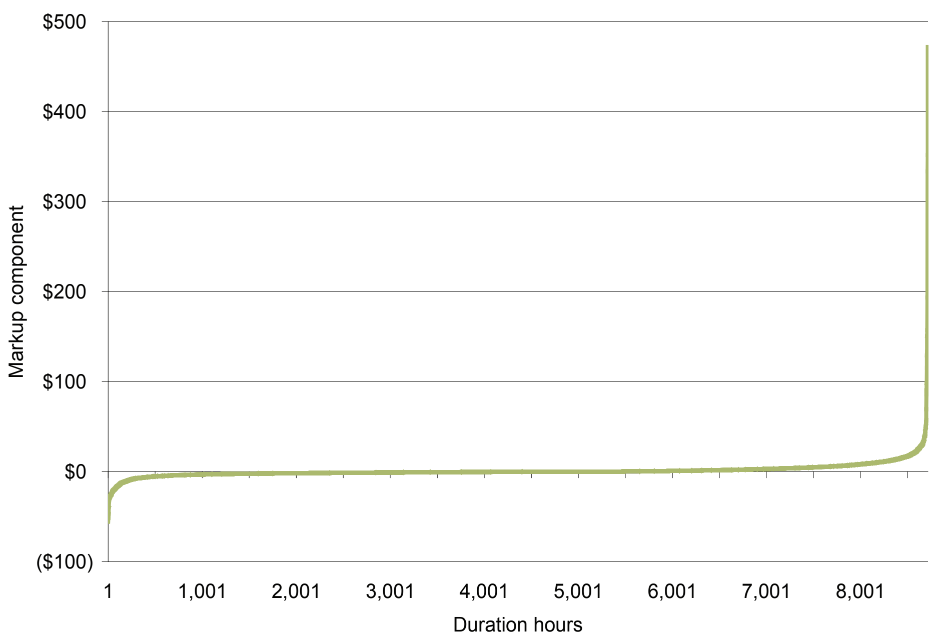
31 For a definition of high-load days, see *2006 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," at "High-Load Events, Scarcity and Scarcity Pricing Events." For the analysis of components of LMP, seven high load days are included when high load days are referenced. The seven days are July 17, July 18, July 19, July 31, August 1, August 2 and August 3.

Table 2-33 Monthly markup components of load-weighted LMP: Calendar year 2006

Month	Markup Component (All Hours)	On-Peak Markup Component	Off-Peak Markup Component
Jan	($1.22)	$0.52	($2.92)
Feb	$1.94	$1.83	$2.05
Mar	($0.76)	($1.12)	($0.35)
Apr	$1.82	$3.50	$0.16
May	$1.24	$2.86	($0.58)
Jun	$0.72	$1.81	($0.66)
Jul	$2.17	$3.45	$0.93
Aug	$7.06	$12.10	$0.60
Sep	$0.13	$0.74	($0.48)
Oct	$0.94	$2.12	($0.37)
Nov	$2.42	$3.87	$0.90
Dec	$0.78	$2.31	($0.61)
2006	$1.54	$3.08	($0.10)

Figure 2-5 shows a duration curve for the hourly markup component of LMP for the year. The figure shows that for 5,351 hours, or 61 percent, the markup component of LMP was $0.00 or lower. There were 100 hours, or 1 percent, with a markup component of LMP greater than $25.00.

Figure 2-5 Markup price impact duration curve: Calendar year 2006



Markup Component of Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-34. The smallest zonal all hours' markup component was in the DLCO Control Zone, $0.73 per MWh, while the highest all hours' zonal markup component was in the RECO Control Zone, $2.45 per MWh. On peak, the smallest zonal markup was in the DLCO Control Zone, $1.65 per MWh, while the highest markup was in the RECO Control Zone, $4.47 per MWh. Off peak, the smallest zonal markup was in the PENELEC Control Zone, -$0.61 per MWh, while the highest markup was in the PEPCO Control Zone, $0.16 per MWh.

Table 2-34 Average zonal markup component: Calendar year 2006

Zone	Markup Component (All Hours)	On-Peak Markup Component	Off-Peak Markup Component
AECO	$1.80	$3.74	($0.24)
AEP	$0.94	$2.06	($0.22)
AP	$1.36	$2.75	($0.08)
BGE	$1.95	$3.70	$0.11
ComEd	$1.14	$2.26	($0.07)
DAY	$1.09	$2.22	($0.14)
DLCO	$0.73	$1.65	($0.26)
DPL	$2.08	$4.18	($0.11)
Dominion	$1.61	$3.15	$0.00
JCPL	$1.96	$3.96	($0.29)
Met-Ed	$1.54	$3.17	($0.24)
PECO	$1.83	$3.71	($0.21)
PENELEC	$0.74	$2.00	($0.61)
PEPCO	$2.11	$3.92	$0.16
PPL	$1.47	$3.14	($0.35)
PSEG	$2.21	$4.24	($0.04)
RECO	$2.45	$4.47	$0.00

Markup by System Price Levels

Table 2-35 shows the average markup component of observed price when the PJM system LMP was in the identified price range.

Table 2-35 Average markup by price category: Calendar year 2006

	Average Markup Component	Frequency
Below $20	($1.41)	4%
$20 to $39.99	($1.31)	44%
$40 to $59.99	$0.31	28%
$60 to $79.99	$2.93	13%
$80 to $99.99	$5.61	7%
$100 to $119.99	$7.28	3%
$120 to $139.99	$8.54	1%
$140 to $159.99	$11.38	0%
Above $160	$63.98	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.

Table 2-36 compares the markup components of price of exempt and non-exempt units in 2006. Of the 56 generators that are exempt from offer capping, 43 were marginal in 2006. The 43 marginal exempt units accounted for $0.56, 36 percent, of the total markup component of LMP in 2006. Of the 43 units, the top eight exempt units contributed 90 percent of the total markup component of exempt units, or 33 percent of the total markup component for all of PJM. The average markup per exempt unit is about nine times higher than for non-exempt units, and the average markup for the top eight exempt units is about 43 times higher

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

than for non-exempt units. This analysis does not address whether these units would have been offer 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.

Table 2-36 Comparison of exempt and non-exempt markup component: Calendar year 2006

	Units Marginal	Markup Component
Non-Exempt Units	667	$0.98
Exempt Units	43	$0.56

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 more than 80 percent 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 varying 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 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

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. 132 (Effective January 27, 2007).
39 OA, Fifth Revised Sheet No. 132 (Effective January 27, 2007).

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 2-37 shows the number of FMUs and AUs in each month of 2006. Prior to the FERC order approving the settlement agreement with multiple types of FMUs in March 2006, there was only one type of FMU and that FMU designation was for a full year. For example, in December 2006, there were 16 FMUs and 13 AUs in Tier 1, 24 FMUs and 16 AUs in Tier 2, and 31 FMUs and 30 AUs in Tier 3.

Table 2-37 Frequently mitigated units and associated units by month: Calendar year 2006[40]

	FMUs and AUs		
Month	Tier 1	Tier 2	Tier 3
January	0	0	43
February	0	0	49
March	21	27	87
April	10	28	87
May	11	27	87
June	5	27	90
July	9	26	87
August	18	20	88
September	22	19	73
October	32	30	72
November	32	33	67
December	29	40	61

Table 2-38 shows the price component of the offer-cap adders for frequently mitigated units and associated units on LMP in each zone.[41] 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 component occurs, not the location of the FMUs or AUs. The additional energy cost is the affected load multiplied by the locational price impacts.

40 Table 2-37 reflects a daily average for the month of January only.

41 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 2-38 Cost impact of FMUs and AUs by zone: Calendar year 2006

Zone	FMU and AU Marginal Energy Impacts (Millions)	Total Energy Cost (Millions)	Percent	LMP Impact
AECO	$18.12	$655.37	2.8%	$1.66
AEP	$12.51	$5,644.44	0.2%	$0.08
AP	$17.30	$2,210.98	0.8%	$0.26
BGE	$26.29	$1,936.32	1.4%	$0.76
ComEd	$9.84	$4,150.10	0.2%	$0.08
DAY	$1.24	$746.24	0.2%	$0.06
Dominion	$48.18	$5,172.27	0.9%	$0.51
DPL	$5.16	$1,000.02	0.5%	$0.27
DLCO	$0.29	$556.44	0.1%	$0.02
JCPL	$7.90	$1,266.04	0.6%	$0.33
Met-Ed	$7.13	$779.71	0.9%	$0.44
PECO	$11.91	$2,082.28	0.6%	$0.28
PENELEC	$2.13	$778.33	0.3%	$0.15
PEPCO	$29.68	$1,872.12	1.6%	$0.90
PPL	$11.37	$2,112.98	0.5%	$0.24
PSEG	$12.61	$2,541.69	0.5%	$0.26
RECO	$0.45	$85.20	0.5%	$0.29
PJM	$215.06	$37,140.73	0.6%	$0.31

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.[42] 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.[43] 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.[44]

42 See *2006 State of the Market Report,* Volume II, Section 2, "Energy Market, Part I," at Figure 2-1 "Average PJM aggregate supply curves: Summers 2005 and 2006 ."

43 For a definition of high-load days, see *2006 State of the Market Report,* Volume II, Section 3, "Energy Market, Part 2," at "High-Load Events, Scarcity and Scarcity Pricing Events."

44 See *2006 State of the Market Report,* Volume II, Section 3, "Energy Market, Part 2," at "2006 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 2-6 shows the load-weighted, hourly average markup component of price for the summer of 2006.

Figure 2-6 Average hourly markup and load: Summer 2006

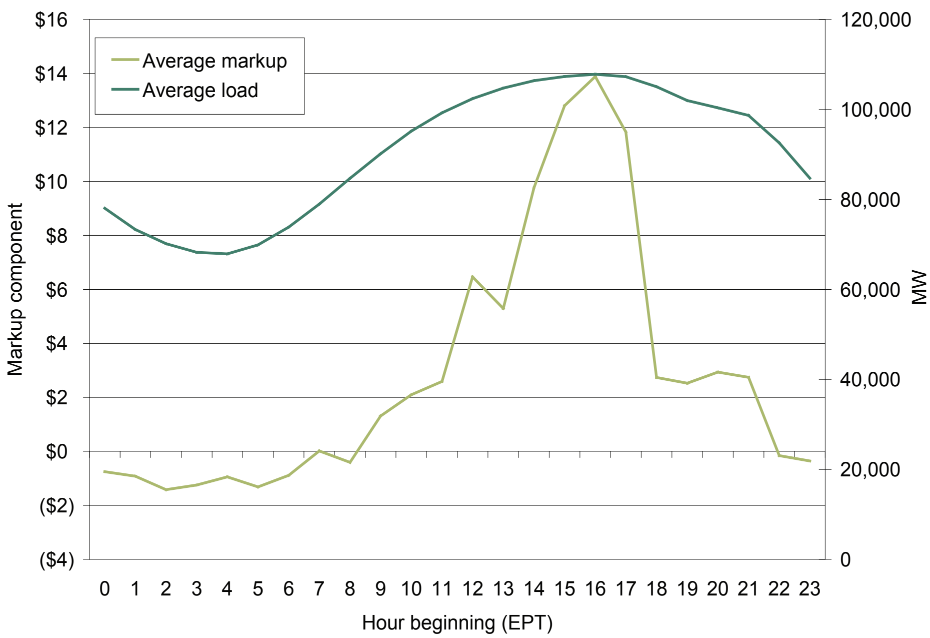


Table 2-39 shows that $0.60 per MWh, or 39 percent, of the total markup component of price occurs on high-load days. In addition, for units subject to offer capping for local market power (non-exempt units), 50 percent of the total markup component of price occurs on high-load days. For units exempt from offer capping, 20 percent of the total markup component of price occurs on high-load days.

Table 2-39 Markup contribution of exempt and non-exempt units: Calendar year 2006

	Exempt Markup Component	Non-exempt Markup Component	Total
High-Load Days	$0.11	$0.49	$0.60
Balance of Year	$0.45	$0.49	$0.94
Total	$0.56	$0.98	$1.54

Market Performance: Load and LMP

Load

The PJM system load and LMP reflect the configuration of the entire regional transmission organization (RTO).

Annual Average Real-Time Load and Load Duration

Table 2-40 presents summary load statistics for the nine-year period 1998 to 2006. The average load of 79,471 MWh in 2006 was 1.7 percent higher than the 2005 annual average.

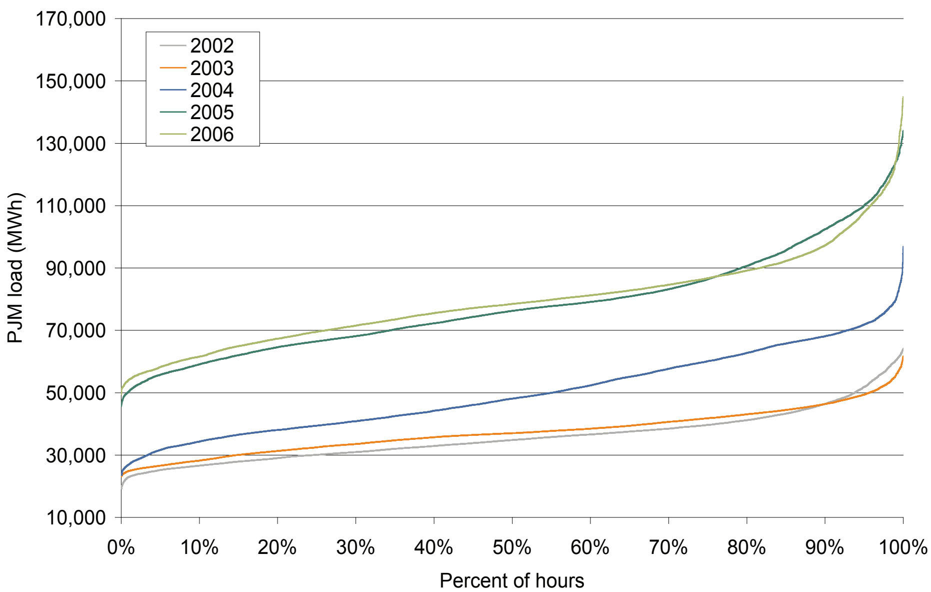
Table 2-40 PJM average real-time load: Calendar years 1998 to 2006

	PJM 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%)

Load Duration

Figure 2-7 shows real-time load duration curves from 2002 to 2006. A load duration curve shows the percent of hours that load was at, or below, a given level for the year.

Figure 2-7 PJM real-time load duration curves: Calendar years 2002 to 2006



Real-Time and Day-Ahead Load

Real-time load is the actual load on the system during the operating day.

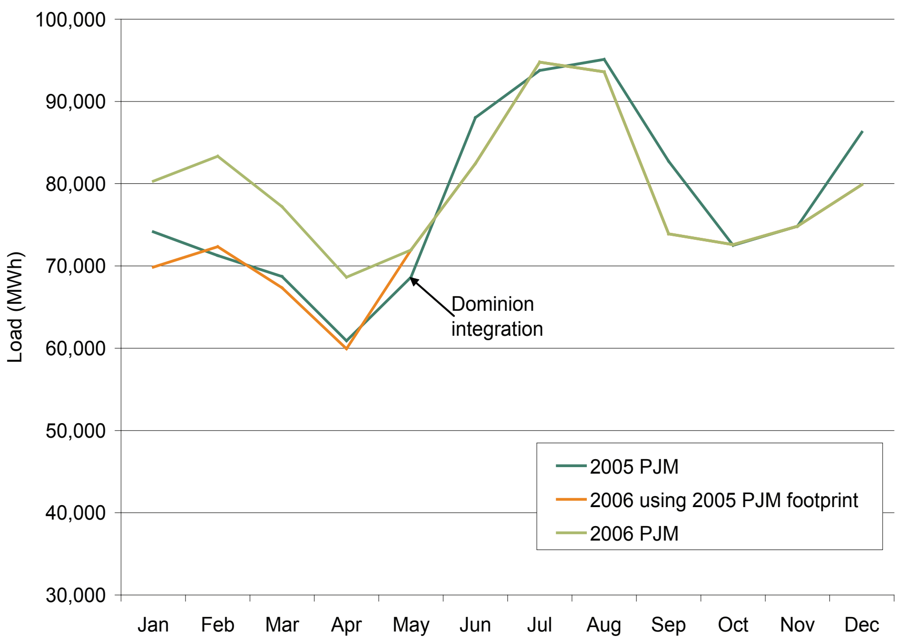
In the Day-Ahead Energy Market, three types of financially binding demand bids are made and cleared:

- **Fixed-Demand Bid.** Bid to purchase a defined MW level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MW 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 MW 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.

On average, PJM real-time load increased in 2006 by 1.7 percent over 2005, but this increase reflected the fact that the first four months of 2006 included Dominion load which was not present in the four months of

2005.[45] The 2006 PJM real-time average load, calculated to be directly comparable to 2005 by excluding the 2006 load resulting from integration of Dominion for the first four months, was lower than in 2005 by about 2.5 percent. Figure 2-8 shows the monthly average real-time loads for 2006 with and without the Dominion integration for the first four months.

Figure 2-8 PJM average real-time load: Calendar years 2005 to 2006



45 All load data are PJM accounting load.

Load is significantly affected by temperature, especially in the summer months. THI is a measure of effective temperature using temperature and relative humidity. There is a correlation between THI and PJM summer load. Table 2-41 shows the monthly minimum, average and maximum of the PJM hourly THI for the summer months in 2005 and 2006.[46] When comparing 2006 to 2005, changes in THI were mixed, consistent with the changes in load. For the summer months of 2006, the average THI was 67.55, 1.4 percent lower than the average 68.54 THI for 2005. However, the summer maximum THI (84.39) and minimum THI (42.95) in 2006 were 3.4 percent and 14.4 percent higher than the summer maximum THI (81.58) and minimum THI (37.53) in 2005.

Table 2-41 Monthly minimum, average and maximum of PJM hourly THI: Calendar years 2005 to 2006

	2005			2006			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
May	37.53	57.62	70.11	42.95	60.47	78.88	14.4%	4.9%	12.5%
Jun	54.54	70.54	79.75	53.22	67.82	78.65	(2.4%)	(3.9%)	(1.4%)
Jul	62.30	73.49	81.44	58.23	73.63	82.17	(6.5%)	0.2%	0.9%
Aug	61.06	73.20	81.58	58.71	72.32	84.39	(3.8%)	(1.2%)	3.4%
Sep	45.67	67.92	77.06	47.16	63.38	73.59	3.3%	(6.7%)	(4.5%)

Table 2-42 presents summary statistics for the 2006 day-ahead and real-time load and the average difference between them. The sum of day-ahead cleared fixed-demand and price-sensitive demand averaged 2,697 MWh less than real-time load. Total day-ahead load (the sum of the three types of cleared demand bids) averaged 15,322 MWh more than real-time load. Table 2-42 shows that, at 79.0 percent, fixed demand was the largest component of day-ahead load. At 2.0 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 19.0 percent of day-ahead load.

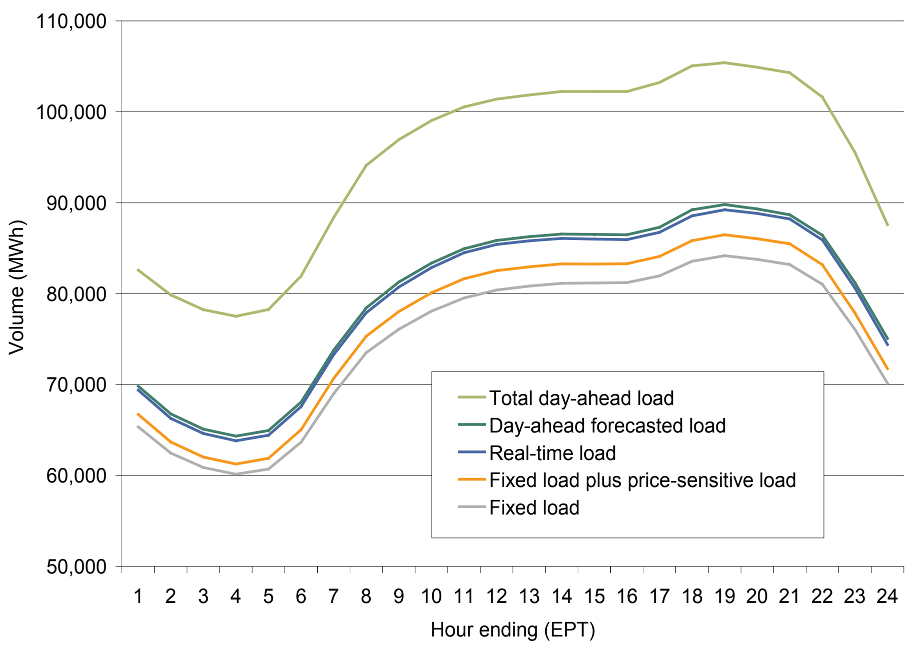
Table 2-42 Cleared day-ahead and real-time load (MWh): Calendar year 2006

	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	74,924	1,850	18,019	94,793	79,471	15,322	(2,697)
Median	73,821	1,835	17,550	93,331	78,473	14,858	(2,692)
Standard Deviation	13,604	801	2,609	16,048	14,534	1,514	(1,095)

46 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. See PJM "Manual 19: Load Data Systems" (June 1, 2006), Section 3, pp. 25-29 for additional information on zonal THI calculations.

Figure 2-9 shows the average 2006 hourly cleared volumes of fixed-demand bids, the sum of cleared fixed-demand bids and price-sensitive bids, day-ahead forecasted load, total day-ahead load and total real-time load. During 2006, average hourly real-time load was higher than cleared fixed-demand load plus cleared price-sensitive load in the Day-Ahead Energy Market, although the reverse was true for 5.2 percent of the hours. When cleared decrement bids are included, day-ahead load always exceeded real-time load.

Figure 2-9 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2006



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,[47] three types of financially binding generation offers are made and cleared:

- **Self-Scheduled.** Offer to supply a fixed block of MW that must run from a specific unit, or as a minimum amount of MW that must run on a specific unit that also has a dispatchable component above the minimum.[48]

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

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

47 All references to day-ahead generation and increment offers are presented in cleared MW in the "Day-Ahead and Real-Time Generation" portion of the *2006 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1."

48 The definition of self-scheduled is based on documentation from the "PJM eMKT Users' Guide" (Revised October 2004), pp. 89-93.

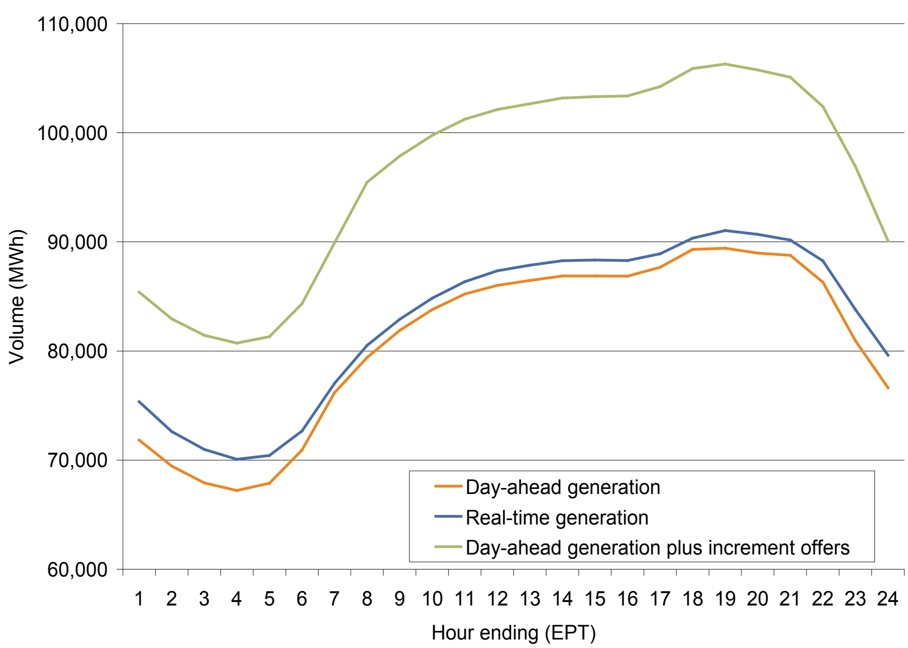
Table 2-43 presents summary statistics for 2006 day-ahead and real-time generation and the average differences between them. Day-ahead cleared generation from physical units averaged 1,828 MWh less than real-time generation. Day-ahead cleared generation plus cleared INC offers averaged 13,543 MWh more than real-time generation. Table 2-43 also shows that cleared generation and INC offers accounted for 84.0 percent and 16.0 percent of day-ahead supply, respectively.

Table 2-43 Day-ahead and real-time generation (MWh): Calendar year 2006

	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	80,952	15,371	96,323	82,780	(1,828)	13,543
Median	79,675	14,842	94,485	80,920	(1,245)	13,565
Standard Deviation	13,631	2,711	15,860	13,709	(78)	2,151

Figure 2-10 shows average hourly cleared volumes of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2006.[49] Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. During 2006, average hourly real-time generation was higher than day-ahead generation from physical units, although the reverse was true for 24.1 percent of the hours. When cleared increment offers are included, average hourly total day-ahead cleared MW offers exceeded real-time generation.

Figure 2-10 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2006



49 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.[50]

Real-Time Energy Market Prices

PJM real-time energy market prices decreased in 2006. The simple hourly average system LMP for 2006 was 15.2 percent lower than the 2005 annual average, $49.27 per MWh versus $58.08 per MWh.[51] When hourly load levels are reflected, the hourly load-weighted LMP for 2006 was 15.9 percent lower than it had been for the 2005 annual average, $53.35 per MWh versus $63.46 per MWh.

Average Hourly, Unweighted System LMP

Table 2-44 shows the simple average hourly LMP for the nine-year period 1998 to 2006.[52]

Table 2-44 PJM average hourly LMP (Dollars per MWh): Calendar years 1998 to 2006

	Locational Marginal Price (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%)

Zonal LMP

Table 2-45 shows PJM's 2005 and 2006 zonal real-time average LMPs. The largest zonal decrease was in the Dominion Control Zone which experienced a $16.83 decrease over 2005 and the smallest decrease was in the DLCO Control Zone which experienced a $4.33 decrease over 2005.

50 See *2006 State of the Market Report,* Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and comparisons.

51 The simple average, system LMP is the average of the hourly LMP in each hour without any weighting.

52 Hourly statistics were calculated from hourly, integrated, PJM system LMPs and market-clearing prices (MCPs) for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Table 2-45 Zonal real-time energy market LMP (Dollars per MWh): Calendar years 2005 to 2006

	2005	2006	Difference	Difference as Percent of 2005
AECO	$68.17	$55.53	($12.64)	(18.5%)
AEP	$47.36	$42.24	($5.12)	(10.8%)
AP	$58.21	$48.71	($9.50)	(16.3%)
BGE	$67.92	$57.40	($10.52)	(15.5%)
ComEd	$46.50	$41.52	($4.98)	(10.7%)
DAY	$45.95	$41.21	($4.74)	(10.3%)
DLCO	$43.67	$39.34	($4.33)	(9.9%)
Dominion	$73.27	$56.44	($16.83)	(23.0%)
DPL	$65.64	$53.09	($12.55)	(19.1%)
JCPL	$65.65	$51.80	($13.85)	(21.1%)
Met-Ed	$64.24	$52.66	($11.58)	(18.0%)
PECO	$65.44	$52.40	($13.04)	(19.9%)
PENELEC	$56.55	$46.64	($9.91)	(17.5%)
PEPCO	$69.10	$58.85	($10.25)	(14.8%)
PPL	$63.05	$51.52	($11.53)	(18.3%)
PSEG	$69.82	$54.57	($15.25)	(21.8%)
RECO	$67.61	$53.88	($13.73)	(20.3%)

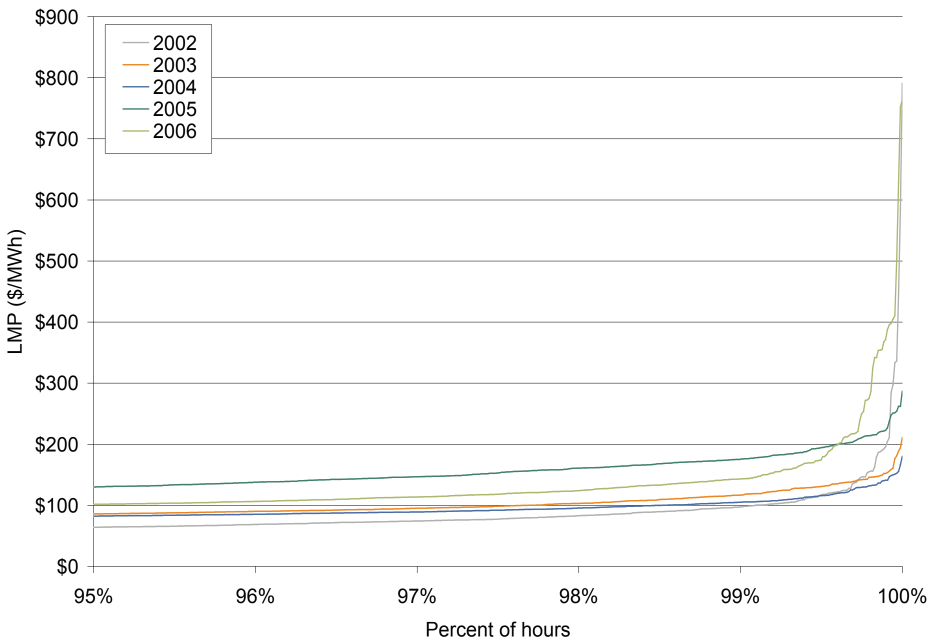
Price Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-11 presents price duration curves for hours above the 95th percentile from 2002 to 2006. In the year 2002, prices exceeded $100 per MWh for 0.9 percent of the hours, in 2003 for 2.3 percent of the hours, in 2004 for 1.5 percent of the hours, in 2005 for 12.6 percent of the hours and in 2006 for 5.3 percent of the hours. As Figure 2-11 shows, LMPs were less than $100 per MWh during 95 percent or more of the hours for the years 2002 to 2004 and less than $150 during 95 percent or more of the hours in 2005 and 2006.

Figure 2-11 shows that in 2002 LMP exceeded $150 per MWh for 20 hours and exceeded $700 per MWh for only one hour. Prices in 2003 exceeded $150 per MWh for 11 hours and exceeded $200 per MWh for only one hour. Prices in 2004 exceeded $150 per MWh for only five hours. Prices in 2005 exceeded $150 per MWh for 234 hours and exceeded $200 per MWh for 35 hours. Prices in 2006 exceeded $150 per MWh for 76 hours, exceeded $200 per MWh for 35 hours and exceeded $500 per MWh for four hours with the maximum LMP of $763.80 per MWh occurring on August 1 during the hour ended 1800 EPT.[53]

53 See *2006 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 2002 to 2006.”

Figure 2-11 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2002 to 2006



Load-Weighted LMP

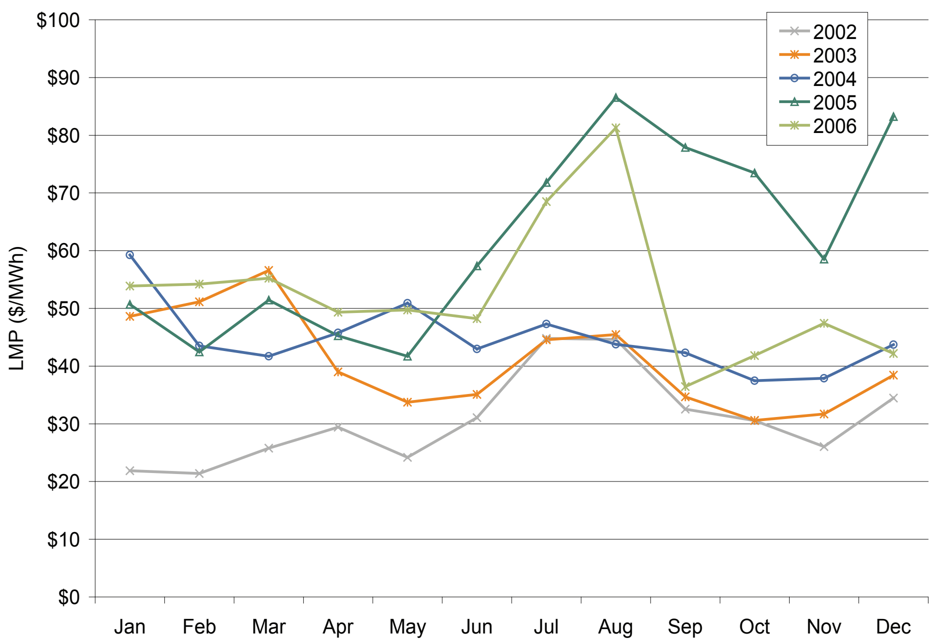
Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than simple average prices. Load-weighted LMP reflects the average LMP paid for actual MWh generated and consumed during a year. Load-weighted LMP is the average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

Table 2-46 PJM load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2006

	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%)

As Table 2-46 shows, 2006 load-weighted LMP dropped to $53.35 per MWh, 15.9 percent lower than it had been in 2005, 20.3 percent higher than in 2004 and 29.4 percent higher than in 2003.[54] Figure 2-12 shows the PJM system monthly load-weighted LMP from 2002 through 2006.

Figure 2-12 Monthly load-weighted, average LMP: Calendar years 2002 to 2006



Components of Real-Time 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 costs depending on generating technology, unit age and other factors. The impact of fuel costs on marginal costs 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 2005 and 2006, the 2006 load-weighted LMP was adjusted to reflect the changes 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]

In prior years, the 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.

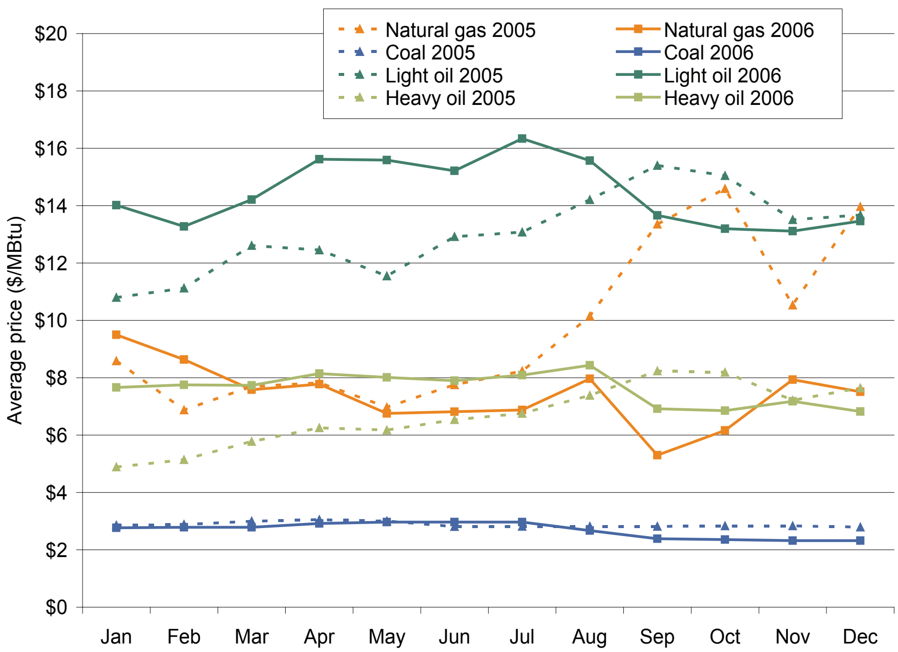
54 See *2006 State of the Market Report*, Volume II, Appendix C, "Energy Market," for on-peak and off-peak, load-weighted LMP details and Appendix H, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

55 See *2006 State of the Market Report*, Volume II, Section 2,"Energy Market, Part 1," at Table 2-30, "Type of fuel used by marginal units: Calendar years 2004 to 2006."

56 For more information, see *2006 State of the Market Report*, Volume II, Appendix I, "Sensitivity Factors."

The dominant fuels in PJM, coal and natural gas, both declined in cost in 2006. In 2006, coal prices were 6.9 percent lower than in 2005. Natural gas prices were 23.9 percent lower in 2006 than in 2005. No. 2 (light) oil prices were 10.8 percent higher and No. 6 (heavy) oil prices were 14.1 percent higher in 2006 than in 2005. Figure 2-13 shows average, daily delivered coal, natural gas and oil prices for units within PJM.[57]

Figure 2-13 Spot average fuel price comparison: Calendar years 2005 to 2006



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.

Table 2-47 compares the 2006 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2005 load-weighted, average LMP. The load-weighted, average LMP for 2006 was 15.9 percent lower than the load-weighted, average LMP for 2005. The fuel-cost-adjusted, load-weighted, average LMP in 2006 was 5.6 percent lower than the load-weighted LMP in 2005. If fuel costs for the year 2006 had been the same as for 2005, the 2006 load-weighted LMP would have been higher, $59.89 per MWh instead of $53.35 per MWh. Net fuel-cost reductions were a substantial part (64.7 percent) of the reason for lower LMP in 2006, but prices would have been lower in 2006 even if fuel costs had remained at 2005 levels.

Table 2-47 PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2005 Load-Weighted LMP	2006 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$63.46	$59.89	(5.6%)
Median	$52.93	$49.99	(5.5%)
Standard Deviation	$38.10	$38.34	0.6%

Table 2-48 compares the 2006 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2005 load-weighted, average LMP on a monthly basis.

Table 2-48 Monthly PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

Month	2005 Load-Weighted LMP	2006 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Jan	$50.69	$47.29	(6.7%)
Feb	$42.47	$49.01	15.4%
Mar	$51.43	$54.37	5.7%
Apr	$45.27	$50.98	12.6%
May	$41.72	$51.45	23.3%
Jun	$57.34	$49.73	(13.3%)
Jul	$71.86	$74.18	3.2%
Aug	$86.60	$86.50	(0.1%)
Sep	$77.87	$56.74	(27.1%)
Oct	$73.64	$65.49	(11.1%)
Nov	$58.53	$62.12	6.1%
Dec	$83.23	$57.76	(30.6%)

Table 2-49 compares the 2006 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2005 load-weighted, average LMP on a zonal basis.

Table 2-49 Zonal fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Calendar year 2006

Zone	2005 Load-Weighted LMP	2006 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
AECO	$75.46	$68.84	(8.8%)
AEP	$50.67	$50.76	0.2%
AP	$61.91	$56.91	(8.1%)
BGE	$74.66	$69.73	(6.6%)
ComEd	$50.60	$50.71	0.2%
DAY	$49.63	$50.18	1.1%
DLCO	$47.01	$47.84	1.8%
DPL	$71.58	$64.22	(10.3%)
Dominion	$80.94	$68.92	(14.8%)
JCPL	$73.20	$64.15	(12.4%)
Met-Ed	$69.73	$63.10	(9.5%)
PECO	$71.56	$63.40	(11.4%)
PENELEC	$59.63	$54.99	(7.8%)
PEPCO	$76.39	$71.86	(5.9%)
PPL	$67.67	$61.48	(9.2%)
PSEG	$75.91	$67.93	(10.5%)
RECO	$75.91	$68.29	(10.0%)

Components of Real-Time 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 2-50 shows that 38.7 percent of the annual, load-weighted LMP was the result of coal costs, 32.3 percent was the result of gas costs and 10.1 percent was the result of the cost of SO_2 emission allowances. Fuel costs, overall, accounted for 80.9 percent of marginal costs and for 76.0 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 2-50.[58]

Table 2-50 Components of annual PJM load-weighted, average LMP: Calendar year 2006

Element	Contribution to LMP	Percent
Coal	$20.67	38.7%
Gas	$17.23	32.3%
Oil	$2.65	5.0%
Uranium	$0.00	0.0%
Wind	$0.01	0.0%
NO_x	$1.53	2.9%
SO_2	$5.39	10.1%
VOM	$2.67	5.0%
Markup	$1.54	2.9%
Constrained Off	$1.06	2.0%
NA	$0.59	1.1%

Day-Ahead Energy Market LMP

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 as virtual offers and bids. Virtual offers and bids provide participants the flexibility to, for example, 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 both be marginal, based on the way in which the optimization algorithm works.

Table 2-51 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 2006.[59] Together, increment offers and decrement bids represented 50.7 percent of the marginal bids or offers in 2006.

58 Calculated values shown in Table 2-50 are based on unrounded underlying data and may differ from calculations based on the rounded values presented in the table.

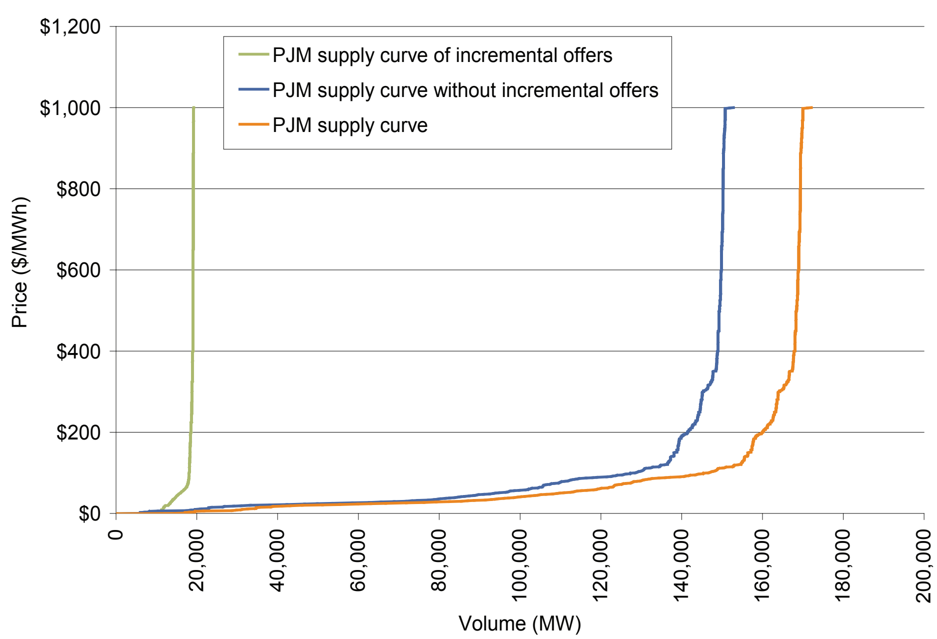
59 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

Table 2-51 Type of day-ahead marginal units: Calendar year 2006

Month	Generation	Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	23.7%	29.3%	30.6%	14.9%	1.5%
Feb	19.6%	31.5%	31.9%	14.8%	2.2%
Mar	14.2%	40.8%	32.1%	11.7%	1.2%
Apr	12.1%	44.2%	31.9%	10.1%	1.7%
May	14.1%	37.8%	31.0%	15.9%	1.2%
Jun	15.3%	31.6%	34.6%	16.6%	1.9%
Jul	12.4%	30.7%	33.2%	22.8%	0.9%
Aug	14.1%	24.1%	40.6%	20.5%	0.7%
Sep	21.2%	28.5%	31.1%	18.8%	0.4%
Oct	17.8%	27.7%	37.1%	16.9%	0.5%
Nov	17.5%	21.4%	42.0%	18.3%	0.7%
Dec	27.5%	25.9%	32.6%	13.1%	0.9%
Annual	16.7%	31.4%	34.1%	16.6%	1.1%

Figure 2-14 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 2006. There were average hourly increment offers of 19,253 MW and average hourly total offers of 172,099 MW for the example day.

Figure 2-14 PJM day-ahead aggregate supply curves: 2006 example day



Price Convergence

When the PJM Day-Ahead Energy Market was introduced, it was expected that competition, exercised substantially through the use of virtual offers and bids, would cause prices in the Day-Ahead and Real-Time Energy Market to converge. Price convergence does not necessarily mean a zero or even a very small difference in prices between day ahead and real time as 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. The fact that there is 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 Market fluctuate continuously and substantially from positive to negative. (See Figure 2-16.) There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis. (See Figure 2-17)

As Table 2-52, Figure 2-15, Figure 2-17 and Figure 2-18 show, day-ahead and real-time prices were relatively close, on average, during 2006. PJM average day-ahead prices were lower than real-time prices by $1.17 per MWh during 2006. On average, day-ahead prices were lower than real-time prices 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 2-52 shows that during 2006, average LMP in the Real-Time Energy Market was $1.17 per MWh or 2.4 percent higher than average LMP in the Day-Ahead Energy Market. The real-time median LMP was 6.7 percent lower than day-ahead, median LMP, reflecting an average difference of $2.76 per MWh. Consistent with the price duration curve (See Figure 2-15), price dispersion in the Real-Time Energy Market was 28.4 percent greater than in the Day-Ahead Energy Market, with an average difference in standard deviation between the two of $9.29 per MWh.

Table 2-52 Day-ahead and real-time energy market LMP (Dollars per MWh): Calendar year 2006

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$48.10	$49.27	$1.17	2.4%
Median	$44.21	$41.45	($2.76)	(6.7%)
Standard Deviation	$23.42	$32.71	$9.29	28.4%

The difference in prices between real time and day ahead is, in part, the result of volatility in the Real-Time Market that is difficult or impossible to anticipate in the Day-Ahead Market. In 2006, real-time prices were higher than day-ahead prices by more than $150 per MWh for 11 hours and by more than $200 per MWh for 10 hours. In 2005, real-time prices were higher than day-ahead prices by more than $150 per MWh for two hours and were never higher by more than $200 per MWh. If the hours with price differences greater than $150 per MWh are excluded, the difference between real-time prices and day-ahead prices is $0.82 per MWh in 2006 rather than $1.17 and $0.15 per MWh in 2005 rather than $0.19.

Figure 2-15 shows the 2006 day-ahead and real-time price duration curves. The two duration curves show day-ahead and real-time prices for the year, ordered by price level, but do not compare prices for individual hours. Although real-time prices were higher than day-ahead prices on average, real-time prices were lower than day-ahead prices for 59.5 percent of the hours. During the hours when real-time prices were higher than day-ahead prices, the average positive difference between real-time and day-ahead prices was $15.66 per MWh. During the hours when real-time prices were less than day-ahead prices, the average negative difference was -$8.67 per MWh.

Figure 2-15 PJM price duration curves for the Day-Ahead and Real-Time Energy Market: Calendar year 2006

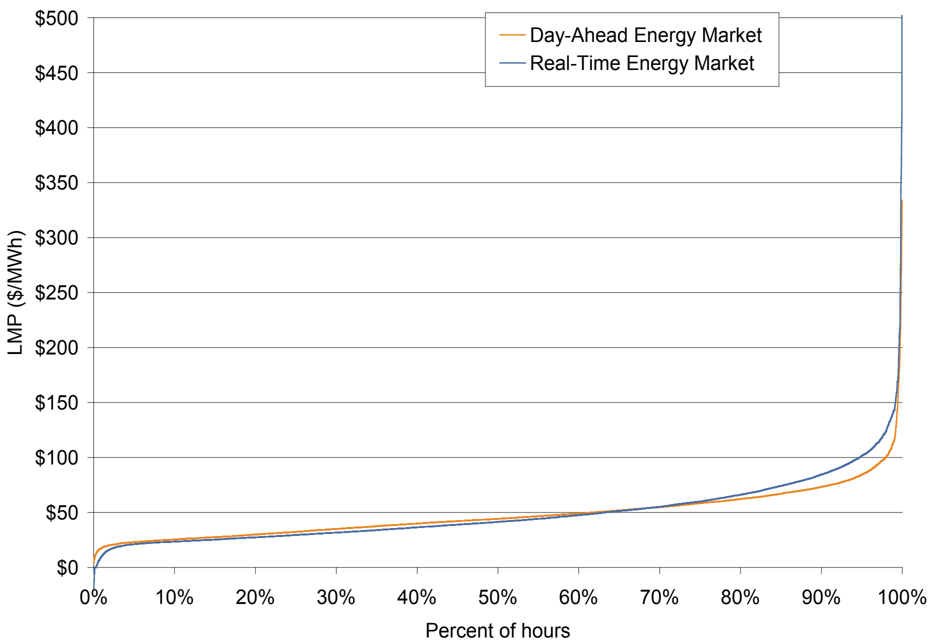


Figure 2-16 shows the hourly differences between day-ahead and real-time LMP in 2006. Although the average difference between the Day-Ahead and Real-Time Energy Market was $1.17 per MWh for the entire year, Figure 2-16 demonstrates the considerable actual variation, both positive and negative, between day-ahead and real-time prices. The highest difference between real-time and day-ahead LMP was $515.04 per MWh for the hour ended 1800 on August 1, 2006, when the real-time LMP was $763.80 (peak LMP for 2006) and day-ahead LMP was $248.76.

Figure 2-16 Hourly real-time minus day-ahead average LMP: Calendar year 2006

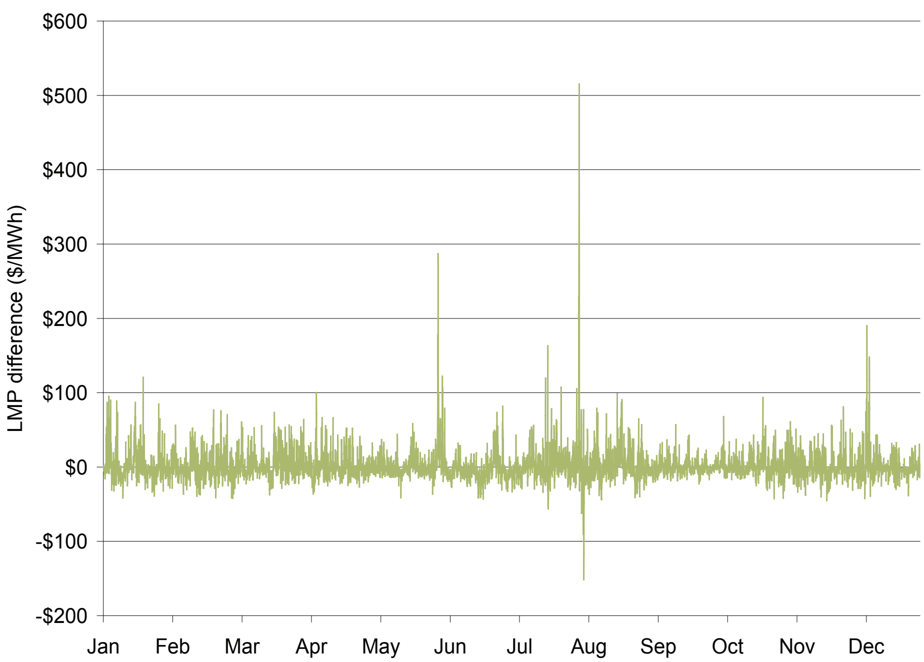


Figure 2-17 shows the monthly differences between day-ahead and real-time LMP in 2006. The highest monthly difference was in August, which was the month with annual peak load and peak system real-time LMP.

Figure 2-17 Monthly real-time minus day-ahead average LMP: Calendar year 2006

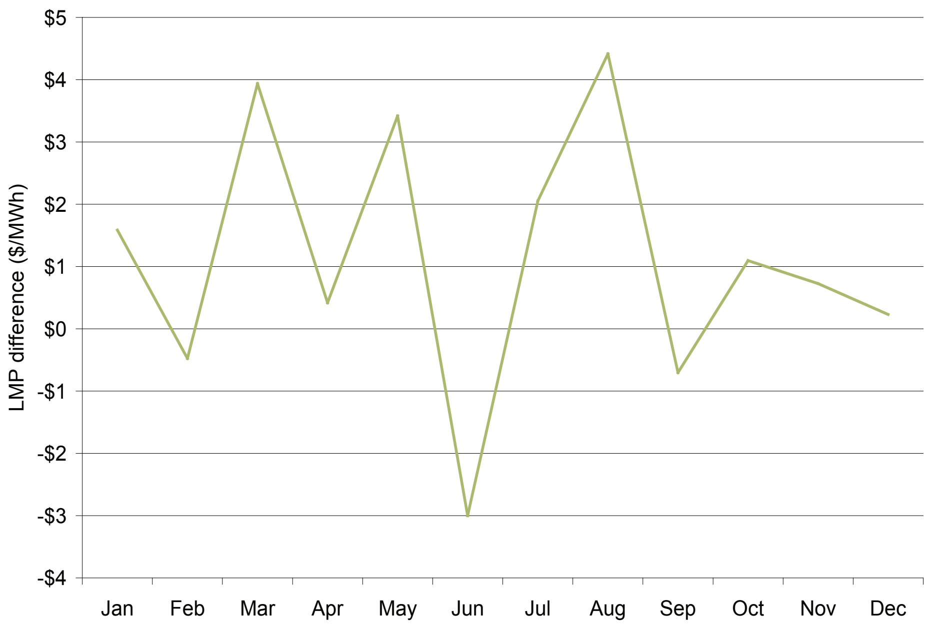
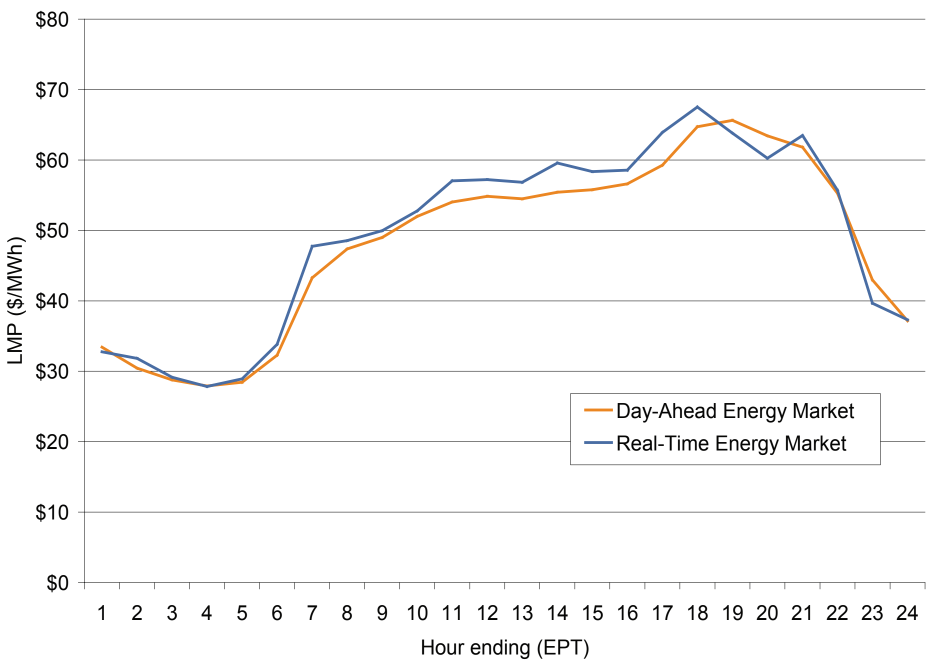


Figure 2-18 shows that day-ahead and real-time LMPs were close on an average hourly basis, but that average real-time LMP was greater than average day-ahead LMP for 19 out of 24 hours.[60]

Figure 2-18 PJM hourly system average LMP: Calendar year 2006



Zonal Price Convergence

Table 2-53 shows the 2006 zonal day-ahead and real-time average LMPs. The difference between zonal day-ahead and real-time LMP ranged from negative $2.07 in the PEPCO Control Zone where the average day-ahead LMP was lower than the average real-time LMP, to $0.06 in the PECO Control Zone, where the average day-ahead LMP was higher than the average real-time LMP.[61]

60 See *2006 State of the Market Report*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.
61 See *2006 State of the Market Report*, Volume II, Section 7, "Congestion," for detailed congestion analysis.

Table 2-53 Zonal day-ahead and real-time energy market LMP (Dollars per MWh): Calendar year 2006

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$54.58	$55.53	($0.95)	(1.7%)
AEP	$41.40	$42.24	($0.84)	(2.0%)
AP	$47.33	$48.71	($1.38)	(2.8%)
BGE	$55.51	$57.40	($1.89)	(3.3%)
ComEd	$41.04	$41.52	($0.48)	(1.2%)
DAY	$40.33	$41.21	($0.88)	(2.1%)
DLCO	$38.96	$39.34	($0.38)	(1.0%)
Dominion	$54.58	$56.44	($1.86)	(3.3%)
DPL	$52.99	$53.09	($0.10)	(0.2%)
JCPL	$51.23	$51.80	($0.57)	(1.1%)
Met-Ed	$52.64	$52.66	($0.02)	(0.0%)
PECO	$52.46	$52.40	$0.06	0.1%
PENELEC	$46.08	$46.64	($0.56)	(1.2%)
PEPCO	$56.78	$58.85	($2.07)	(3.5%)
PPL	$51.48	$51.52	($0.04)	(0.1%)
PSEG	$53.68	$54.57	($0.89)	(1.6%)
RECO	$53.63	$53.88	($0.25)	(0.5%)

Real-Time Load, Generation, Bilateral and Spot Market

As a general matter, participants in PJM 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. 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 and paying spot market prices for those energy purchases. Real-time and day-ahead energy market transactions are referred to as Spot Market activity because they are transactions made in a short-term market.

The PJM system reliance on self-supply, bilateral contracts and spot purchases to meet load is calculated by summing across all PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 2-54 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchases in 2005 and 2006. In 2006, 92.8 percent of real-time energy market load was supplied by bilateral contracts, 6.2 percent by spot market purchases and 1.0 percent by self-supply. In 2005, 92.1 percent of real-time energy market load was supplied by bilateral contracts, 6.9 percent by spot market purchases and 1.0 percent by self-supply. In 2006, reliance on bilateral contracts increased by 0.7 percentage points, reliance on spot supply decreased by 0.7 percentage points and reliance on self-supply was unchanged.

This approach to the definition of the Spot Market based on how real-time load is met represents a significant change from the method used in prior state of the market reports. In prior reports, the spot market volume was defined simply as the sum of all hourly net positive spot purchases across all PJM billing organizations in the Real-Time Energy Market. However, such spot purchases are not necessarily used to meet system load by a PJM billing organization. If the purchasing organization does not have its own load, then its spot purchases are used to support bilateral sales. Spot purchases used to support bilateral sales were 33.4 percent and 38.1 percent of system load in 2005 and 2006, respectively. As those spot purchases were not used to support system load (those organizations do not have native load), they are not included as spot market purchases in the new method. That is why the spot market share in 2005 (6.9 percent) based on the new method is lower than the spot market share (40.4 percent) based on the old method. The difference is the level of spot market purchases used to support bilateral sales of organizations not serving load.

Table 2-54 Monthly average percentage of real-time self-supply load, bilateral supply load and spot supply load: Calendar years 2005 to 2006

	2005			2006			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	91.0%	7.9%	1.1%	92.4%	6.5%	1.0%	1.4%	(1.4%)	(0.1%)
Feb	90.9%	8.0%	1.1%	92.5%	6.5%	1.0%	1.6%	(1.5%)	(0.1%)
Mar	90.8%	8.0%	1.2%	92.6%	6.4%	1.0%	1.8%	(1.6%)	(0.2%)
Apr	91.0%	7.7%	1.3%	92.7%	6.2%	1.0%	1.7%	(1.5%)	(0.3%)
May	91.7%	7.2%	1.1%	92.7%	6.2%	1.1%	1.0%	(1.0%)	0.0%
Jun	93.0%	6.2%	0.8%	93.2%	5.8%	1.0%	0.2%	(0.4%)	0.2%
Jul	93.1%	6.0%	0.8%	93.3%	5.8%	0.9%	0.2%	(0.2%)	0.1%
Aug	93.1%	6.0%	0.8%	93.2%	6.0%	0.8%	0.1%	0.0%	0.0%
Sep	92.9%	6.2%	1.0%	92.8%	6.1%	1.0%	(0.1%)	(0.1%)	0.0%
Oct	92.4%	6.7%	0.9%	92.2%	6.7%	1.1%	(0.2%)	0.0%	0.2%
Nov	92.0%	7.1%	0.9%	92.6%	6.3%	1.1%	0.6%	(0.8%)	0.2%
Dec	92.3%	6.9%	0.9%	92.6%	6.4%	1.0%	0.3%	(0.5%)	0.1%
Annual	92.1%	6.9%	1.0%	92.8%	6.2%	1.0%	0.7%	(0.7%)	0.0%

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. The 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 real-time prices or to hedge their exposure to those prices 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. 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 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 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.

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).[62] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[63] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007.[64] 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.[65, 66] The same order permitted, for individual participants

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

63 99 FERC ¶ 61,227 (2002).

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

65 114 FERC ¶ 61,201 (February 24, 2006).

66 Analysis of the role of demand-side resources in the Ancillary Service Markets can be found in the *2006 State of the Market*, Volume II, Section 6, "Ancillary Service Markets," at "Synchronized Reserve Market Performance."

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.

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the real 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 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.[67] 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).[68] 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.[69] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[70] 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.[71]

Emergency Program

The number of registered sites with associated MW in the Emergency Program is shown in Table 2-55.[72] On August 2, 2006, there were 1,081.02 MW of available resources in the Emergency Program, a 26 percent decrease from the 1,455.50 MW on July 26, 2005. [73]

Table 2-55 Emergency Program registration: Within 2002 to 2006

Date	Sites	Peak-Day, Registered MW
14-Aug-02	64	509.31
22-Aug-03	84	475.43
03-Aug-04	3,857	1,395.50
26-Jul-05	3,867	1,455.50
02-Aug-06	4,427	1,081.02

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

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

69 99 FERC ¶ 61,139 (2002).

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

71 114 FERC ¶ 61,201 (February 24, 2006).

72 The number of registered sites and associated MW for Emergency and Economic Programs are recorded on peak-load days.

73 The number of registered sites and MW levels are measured as a one-day snapshot, which is different from the method used in previous state of the market reports and in the MMU report to the FERC entitled, “Assessment of PJM Load-Response Program” filed on August 29, 2006. 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 2-56 shows the zonal distribution of DSR capability in the Emergency Program on August 2, 2006. The ComEd Control Zone includes 98 percent of all registered sites and 82 percent of all registered MW in the Emergency Program.

Table 2-56 Zonal capability in the Emergency Program: August 2, 2006

	Sites	MW
AECO	0	0.00
AEP	0	0.00
AP	0	0.00
BGE	2	7.25
ComEd	4,360	884.98
DAY	0	0.00
DLCO	0	0.00
Dominion	0	0.00
DPL	0	0.00
JCPL	0	0.00
Met-Ed	0	0.00
PECO	55	156.49
PENELEC	1	2.20
PEPCO	2	0.20
PPL	4	16.60
PSEG	3	13.30
RECO	0	0.00
Total	4,427	1,081.02

The total MWh of load reductions and the associated payments under the Emergency Program are shown in Table 2-57.[74] Load reduction levels decreased in 2003 by 91 percent from 551 MW in 2002.[75] There was no activity in the program during 2004 because of the mild weather conditions and associated prices. At 3,662 MWh, 2005 had the largest load reduction level since the program began. In 2005, payments under the program were $508 per MWh and 2.5 MWh of actual load reduction per peak-day, registered MW. There was no activity in the Emergency Program during calendar year 2006.

Table 2-57 Performance of Emergency Program participants: Calendar years 2002 to 2006

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	551	$282,756	$513	1.1
2003	49	$26,613	$543	0.1
2004	0	$0	$0	0.0
2005	3,662	$1,859,638	$508	2.5
2006	0	$0	$0	0.0

Economic Program

On August 2, 2006, there were 1,100.65 MW registered in the Economic Program compared to the 2,210.19 MW on July 26, 2005, a decrease of 50 percent.[76] (See Table 2-58.)

Table 2-58 Economic Program registration: Within 2002 to 2006

Date	Sites	Peak-Day, Registered MW
14-Aug-02	96	335.40
22-Aug-03	240	650.56
03-Aug-04	782	875.56
26-Jul-05	2,548	2,210.19
02-Aug-06	253	1,100.65

74 In Table 2-57 and Table 2-60, the MMU includes only data that have been confirmed by PJM.

75 Load reductions are measured by multiplying hourly MW reductions by their duration (expressed in number of hours). Thus a 1 MW reduction for one hour is 1 MWh. A 1 MW reduction in one hour and a 3 MW reduction in a second hour equal 4 MWh.

76 The decrease in Economic Program registered sites includes the impact of both corrections made in 2006 by participants who had registered the same MW in both the Emergency and Economic Programs, and the application of a new rule requiring CSPs to review, update and renew registrations in May of each year.

Table 2-59 shows the zonal distribution of DSR capability in the Economic Program on August 2, 2006. The BGE Control Zone includes 47 percent of sites and 13 percent of registered MW in the Economic Program. The AP Control Zone includes 7 percent of sites and 24 percent of registered MW.

Table 2-59 Zonal capability in the Economic Program: August 2, 2006

	Sites	MW
AECO	2	4.90
AEP	2	121.00
AP	17	259.80
BGE	118	140.28
ComEd	22	24.94
DAY	1	3.50
DLCO	5	59.85
Dominion	5	108.50
DPL	14	60.80
JCPL	3	51.36
Met-Ed	6	23.80
PECO	22	34.10
PENELEC	7	43.10
PEPCO	2	10.30
PPL	10	78.35
PSEG	16	75.07
RECO	1	1.00
Total	253	1,100.65

The total MWh of load reductions and the associated payments under the Economic Program are shown in Table 2-60.[77] Load reduction levels increased to 246,996 MWh in calendar year 2006.[78] Payments per MWh were $70 in 2006. The Economic Program's actual load reduction per peak-day, registered MW increased to 224.4 MWh for calendar year 2006, an increase of 215 percent from 2005.

In the calendar year 2006, the maximum hourly load reduction attributable to the Economic Program was 349 MW on July 28, 2006.

Table 2-60 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	246,996	$17,366,318	$70	224.4

During the calendar year 2006, the Economic Program showed differences in activity among the PJM control zones. For example, the AP Control Zone accounted for 29 percent of all real-time reductions. The BGE Control Zone received 37 percent of all real-time payments. The RECO Control Zone saw no activity in any DSR program. (See Table 2-61.[79]) The total number of curtailed hours for the Economic Program was 46,894 and the total payment amount was $17,366,318.[80]

Overall, approximately 94 percent of the MWh reductions, 91 percent of payments and 96 percent of curtailed hours resulted from the real-time option under the Economic Program. Approximately 5 percent of the MWh reductions, 7 percent of payments and 3 percent of curtailed hours resulted from the day-ahead option. Less than 1 percent of the MWh reductions, 1 percent of the payments and approximately 2 percent of the curtailed hours resulted from the dispatched-in-real-time option of the program. (See Table 2-61.)

77 The "Total MWh" and "Total Payments" shown in Table 2-60 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 2007.

78 The Economic Program payments in Table 2-60 and Table 2-61 do not include settlement adjustments of $64,698 for May, June, July and August 2006 because they have not been assigned to specific customers in the database.

79 The sum of individual zonal numbers may slightly vary from the total values because of rounding.

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

Table 2-61 PJM Economic Program by zonal reduction: Calendar year 2006

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	519	$75,069	397	0	$0	0	0	$0	0	519	$75,069	397
AEP	2,031	$89,867	208	0	$0	0	0	$0	0	2,031	$89,867	208
AP	66,392	$3,135,912	6,545	240	$20,487	10	417	$68,914	167	67,049	$3,225,313	6,722
BGE	38,489	$5,902,972	3,939	0	$0	0	64	$21,687	58	38,553	$5,924,659	3,997
ComEd	17,647	$635,109	4,817	1,703	$123,820	305	164	$29,985	140	19,515	$788,914	5,262
DAY	0	$0	0	586	$60,665	231	0	$0	0	586	$60,665	231
DLCO	284	$26,381	107	0	$0	0	5	$725	7	289	$27,107	114
Dominion	13,150	$1,683,108	740	0	$0	0	0	$0	0	13,150	$1,683,108	740
DPL	5,662	$448,747	2,142	0	$0	0	0	$0	0	5,662	$448,747	2,142
JCPL	0	$0	0	859	$131,041	35	0	$0	0	859	$131,041	35
Met-Ed	71	$6,837	318	0	$0	0	7	$2,572	42	77	$9,409	360
PECO	57,596	$2,027,854	20,115	4,102	$190,107	258	200	$66,270	170	61,898	$2,284,230	20,543
PENELEC	150	$8,711	168	0	$0	0	14	$4,207	20	164	$12,917	188
PEPCO	11,333	$918,224	1,030	0	$0	0	0	$0	0	11,333	$918,224	1,030
PPL	16,470	$718,659	1,317	97	$21,913	190	21	$5,454	46	16,588	$746,026	1,553
PSEG	2,996	$150,623	3,082	5,535	$746,877	151	192	$43,522	139	8,723	$941,022	3,372
RECO	0	$0	0	0	$0	0	0	$0	0	0	$0	0
Total	232,790	$15,828,074	44,925	13,121	$1,294,910	1,180	1,085	$243,335	789	246,996	$17,366,318	46,894
Max	66,392	$5,902,972	20,115	5,535	$746,877	305	417	$68,914	170	67,049	$5,924,659	20,543
Avg	13,694	$931,063	2,643	772	$76,171	69	64	$14,314	46	14,529	$1,021,548	2,758

The DSR business rules provide for larger payments when LMP is greater than or equal to $75 per MWh than when LMP is below $75 per MWh. About 57 percent of all MWh reductions, 62 percent of all curtailed hours and only 16 percent of all Economic Program payments occurred when LMP was less than $75 per MWh. Table 2-62 shows that reductions under the Economic Program when LMP was less than $75 per MWh were dispersed over all hours of the day, with somewhat higher levels of activity in the hours ended 0800 EPT through 2200 EPT.

Table 2-62 Frequency distribution of Economic Program hours when zonal LMP less than $75 MWh (By hours): Calendar year 2006

Hour	Frequency	Percent	Cumulative Frequency	Cumulative Percent
1	473	1.64%	473	1.64%
2	432	1.50%	905	3.14%
3	361	1.25%	1,266	4.39%
4	336	1.16%	1,602	5.55%
5	411	1.42%	2,013	6.98%
6	669	2.32%	2,682	9.30%
7	877	3.04%	3,559	12.34%
8	1,098	3.81%	4,657	12.34%
9	1,388	4.81%	6,045	20.96%
10	1,503	5.21%	7,548	26.17%
11	1,420	4.92%	8,968	31.09%
12	1,684	5.84%	10,652	36.93%
13	1,747	6.06%	12,399	42.98%
14	1,754	6.08%	14,153	49.06%
15	1,631	5.65%	15,784	54.72%
16	1,601	5.55%	17,385	60.27%
17	1,698	5.89%	19,083	66.15%
18	1,628	5.64%	20,711	71.80%
19	1,573	5.45%	22,284	77.25%
20	1,864	6.46%	24,148	83.71%
21	1,460	5.06%	25,608	88.77%
22	1,383	4.79%	26,991	93.57%
23	999	3.46%	27,990	97.03%
24	856	2.97%	28,846	100.00%

Table 2-63 shows that reductions under the Economic Program when zonal LMP was equal to or greater than $75 per MWh were generally higher in hours ended 1100 EPT through 2200 EPT, with the highest levels of activity in hours ended 1300 EPT through 2100 EPT.

Table 2-63 Frequency distribution of Economic Program hours when zonal LMP greater than or equal to $75 per MWh (By hours): Calendar year 2006

Hour	Frequency	Percent	Cumulative Frequency	Cumulative Percent
1	30	0.17%	30	0.17%
2	25	0.14%	55	0.30%
3	12	0.07%	67	0.37%
4	7	0.04%	74	0.41%
5	16	0.09%	90	0.50%
6	93	0.52%	183	1.01%
7	425	2.35%	608	3.37%
8	378	2.09%	986	3.37%
9	398	2.21%	1,384	7.67%
10	488	2.70%	1,872	10.37%
11	968	5.36%	2,840	15.74%
12	985	5.46%	3,825	21.19%
13	1,054	5.84%	4,879	27.03%
14	1,275	7.06%	6,154	34.10%
15	1,379	7.64%	7,533	41.74%
16	1,437	7.96%	8,970	49.70%
17	1,742	9.65%	10,712	59.35%
18	2,095	11.61%	12,807	70.96%
19	1,821	10.09%	14,628	81.05%
20	1,209	6.70%	15,837	87.75%
21	1,160	6.43%	16,997	94.18%
22	703	3.90%	17,700	98.07%
23	168	0.93%	17,868	99.00%
24	180	1.00%	18,048	100.00%

Table 2-64 shows the frequency distribution of Economic Program hourly reductions by real-time zonal LMP in price ranges of $15 per MWh. Activity occurred primarily when LMP was between $15 and $150 per MWh. Most hours, 62 percent, in which reductions took place had an LMP less than $75 per MWh.

Table 2-64 Frequency distribution of Economic Program zonal LMP (By hours): Calendar year 2006

LMP ($/MWh)	Frequency	Percent	Cumulative Frequency	Cumulative Percent
$0 to $15	13	0.03%	13	0.03%
$15 to $30	4,002	8.53%	4,015	8.56%
$30 to $45	8,649	18.44%	12,664	27.01%
$45 to $60	8,732	18.62%	21,396	45.63%
$60 to $75	7,450	15.89%	28,846	61.51%
$75 to $90	6,201	13.22%	35,047	74.74%
$90 to $105	4,324	9.22%	39,371	83.96%
$105 to $120	2,487	5.30%	41,858	83.96%
$120 to $135	1,502	3.20%	43,360	92.46%
$135 to $150	922	1.97%	44,282	94.43%
$150 to $165	406	0.87%	44,688	95.30%
$165 to $180	472	1.01%	45,160	96.30%
$180 to $195	229	0.49%	45,389	96.79%
$195 to $210	235	0.50%	45,624	97.29%
$210 to $225	142	0.30%	45,766	97.59%
$225 to $240	175	0.37%	45,941	97.97%
$240 to $255	102	0.22%	46,043	98.19%
$255 to $270	72	0.15%	46,115	98.34%
$270 to $285	81	0.17%	46,196	98.51%
$285 to $300	34	0.07%	46,230	98.58%
$300 to $315	32	0.07%	46,262	98.65%
$315 to $330	30	0.06%	46,292	98.72%
$330 to $345	21	0.04%	46,313	98.76%
$345 to $360	15	0.03%	46,328	98.79%
$360 to $375	12	0.03%	46,340	98.82%
$375 to $390	42	0.09%	46,382	98.91%
$390 to $405	65	0.14%	46,447	99.05%
$405 to $420	48	0.10%	46,495	99.15%
$420 to $435	14	0.03%	46,509	99.18%
$435 to $450	30	0.06%	46,539	99.24%
$450 to $465	21	0.04%	46,560	99.29%
$465 to $480	24	0.05%	46,584	99.34%
$480 to $495	2	0.00%	46,586	99.34%
$495 to $510	12	0.03%	46,598	99.37%
$510 to $525	33	0.07%	46,631	99.44%
$525 to $540	16	0.03%	46,647	99.47%
> $540	247	0.53%	46,894	100.00%

Active Load Management (ALM)

Table 2-65 shows the number of available ALM MW on the first days of the months, June to September of 2002 to 2006.[81, 82]

Table 2-65 Available ALM MW: Within 2002 to 2006

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

PJM initiated ALM events twice in the summer 2006: August 2 and August 3. In 2006, 241 load-response customers selected the ALM option. In 2006, 29 customers registered as LMP-based contract customers, of which two were ALM customers.[83]

Nonhourly Metered Customer Pilot

PJM created the nonhourly metered program to extend participation in the demand side of the market to smaller customers that lack hourly meters. PJM's nonhourly metered program is a pilot program allowing such customers or their representatives to propose alternate methods for achieving measurable load reductions. PJM approves such methodologies on a case-by-case basis, and participants are otherwise subject to the rules and procedures governing the load-response program in which they have enrolled.

During calendar year 2006, there was no activity under the nonhourly, metered program.

Price Impacts of Demand-Side Response

The price impact of demand-side response can be calculated in a number of ways. In prior reports, 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 necessarily reflect real-time limitations on the ability to dispatch available generation resources. In the *2006 State of the Market Report*, a real-time hourly supply curve was developed for specific hours from actual PJM prices and corresponding loads. The real-time hourly supply curve is the best representation of the relationship between prices and loads (supply curve) in PJM at specific time periods. This method is straightforward and reproducible by any market analyst.

81 See *2006 State of the Market Report,* Volume II, Section 5, "Capacity Market," at Table 5-1,"PJM capacity summary (MW): Calendar year 2006," for statistics on ALM availability during 2006. See also *2006 State of the Market Report,* Volume II, Appendix E, "Capacity Market," at Table E-1,"PJM's ComEd PCI period capacity summer (MW): June to December 2005" for ALM statistics covering the June to December 2005 period.

82 Table 2-65 shows available ALM MW for months when ALM compliance rules were enforced with respect to ALM events.

83 Real-time LMP-based contract customers are only eligible to participate in the dispatched-in-real-time option of the program.

The price impact of Economic Program reductions was calculated for the system peak-load day, August 2, 2006, using the maximum hourly Economic Program reduction of 316.77 MW for that day, and the hourly real-time supply curve. The MMU estimates that the 316.77 MW load reduction would have had a price impact of $22.10, or $0.070 per MW of reduction. For the same period, the MMU estimates that a 1,000 MW reduction would have had a price impact of $69.30, or $0.069 per MW of reduction.[84] The average impact was $.070 per MW of reduction.[85]

Customer Demand-Side Response Programs

DSR Program Summary Data

In evaluating the level of DSR activity, it is important to include not only the activity that occurs in direct response to PJM programs, but also other types of DSR activity. State public utility commission policies on retail competition have had an impact on DSR activity which is reflected in the programs of individual LSEs. PJM conducted surveys of LSEs in June of 2003, 2004, 2005 and 2006 to obtain information about price-responsive tariffs as well as load-response programs offered at the retail level by either electricity distribution companies or competitive electricity suppliers.[86]

The June 2006 PJM survey revealed that only a small amount of load, 1,496 MW, is exposed to LMP.[87] The survey results identified an additional 851 MW of load with a more attenuated link to real-time LMP. This load is partially exposed to real-time prices either directly or through an intermediary competitive supplier.[88]

The survey identified a total of 845 MW enrolled in programs that provide incentives to reduce load during periods of high prices or system emergencies by means other than direct exposure to real-time LMP. These are programs administered by LSEs within the PJM footprint.

84 The MMU method uses the average relationship between the PJM system price and load for the hour prior to the peak-load hour and the hour after the peak-load hour.

85 The average price impact of $0.070 per MW of load reduction at peak load, calculated by the MMU, is approximately equal to the average price impact calculated by the Brattle Group for PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI). See The Brattle Group, “Quantifying Demand Response Benefits in PJM” (January 29, 2007). The Brattle Group, using 2005 data, performed a simulation analysis of a range of load reductions, the maximum of which was 1,119 MW in a single hour. For this reduction, the estimated impact on the Eastern Hub LMP was $83 per MWh and the associated price impact was $0.074 per MW of load reduction. These results are based on underlying simulation results data provided to the MMU by the Brattle Group.

86 In 2006, 36 percent of LSEs responded to the survey, representing 68 percent of LSEs’ peak-load contributions.

87 The 1,496 MW is the sum of 594 MW reported as LMP load plus 902 MW of load identified as paying LMP or paying a price indexed to PJM hub prices, included in the Dynamically Priced category.

88 The 851 MW of load is the sum of the Dynamically Priced category and the Other Contract Mechanism category, less the 902 MW of load in the Dynamically Priced category that is considered LMP-based load. Load-response survey data were provided by the PJM Demand-Side Response Department.

Summary data for demand-side response programs in the PJM footprint are presented in Table 2-66. The data are for PJM programs and for the programs included in response to the PJM survey.[89]

Including the PJM Economic Load-Response Program, the portion of the Dynamically Priced load that is based on LMP or on a price indexed to PJM hub prices there are 2,597 MW of load directly exposed to LMP, or 1.8 percent of peak load.[90] Even including all load exposed in some way to LMP, the total is 3,448 MW, or 2.4 percent of peak load.

Based on the available data and using a very expansive definition of demand-side resources, there are a total of 6,703 MW, or 4.6 percent of peak load, enrolled in demand-side programs of all kinds.

Table 2-66 Demand-side response programs: Summer, 2006

Programs	MW Registered
PJM Programs	
PJM Economic Load-Response Program	1,101
PJM Emergency Load-Response Program	1,081
PJM Active Load-Management Resources	1,679
PJM ALM Resources Included in Load-Response Program	(350)
Total PJM Programs	3,511
Additional Programs Reported By Customers in PJM Survey	
MW under DSR Programs Administered by LSEs' in PJM Territory	
Competitive LSEs' Reported Curtailable Load	138
Distribution LSEs' Reported Direct Load Control Load not in ALM	177
Distribution LSEs' Reported Other Demand Response not in ALM	12
Distribution LSEs' Reported Other (Price-Sensitive) Regulated Retail Rate Load	356
Distribution LSEs' Reported Regulated Interruptible Load	162
Total MW under DSR Programs Administrated by LSEs' in PJM Territory	845
MW with Full and Partial Exposure to Real-Time LMP	
Competitive LSEs' Reported Load - Dynamically Priced	1,644
Competitive LSEs' Reported Load - Other Contract Mechanism	109
Distribution LSEs' Reported LMP-Based Load	594
Total MW with Full and Partial Exposure to Real-Time LMP	2,347
Net Load, Including Survey Responses	6,703

Recognizing that a fully functional demand side of the electricity market means that the default energy price for all customers will be the real-time hourly LMP, there is much progress to be made.

89 Registered MW for PJM programs are as of August 2, 2006 and MW reported in the survey data are as of June 1, 2006.
90 The 2,597 MW are the sum of the 1,101 MW in the PJM Economic Program and the 1,496 MW from the survey data.